Aerospace Report No.
ATR-82(7884)-1, Vol II

ASSESSMENT OF SIMULTANEOUS USE OF NO_x CONTROL SYSTEMS ON STATIONARY SOURCES IN CALIFORNIA

VOLUME II: TECHNICAL DISCUSSION

Prepared by

J. R. Witz and P. P. Leo

February 1982

Government Support Operations
THE AEROSPACE CORPORATION
El Segundo, California 90245

Prepared for

THE STATE OF CALIFORNIA
AIR RESOURCES BOARD
Sacramento, California 95812

Contract No. A9-117-30

TD
885.5
N5
W5
COPY
V.2

Aerospace Report No.
ATR-82(7884)-1, Vol II

ASSESSMENT OF SIMULTANEOUS USE OF NO_x CONTROL SYSTEMS ON STATIONARY SOURCES IN CALIFORNIA

VOLUME II: TECHNICAL DISCUSSION

Prepared by

J. R. Witz and P. P. Leo

February 1982

Government Support Operations
THE AEROSPACE CORPORATION
El Segundo, California 90245

Prepared for

THE STATE OF CALIFORNIA
AIR RESOURCES BOARD
Sacramento, California 95812

Contract No. A9-117-30

DISCLAIMER

The statements and conclusions in this report are those of the contractor and not necessarily those of the California Air Resources Board. The mention of commercial products, their source or their use in connection with material reported herein, is not to be construed as either an actual or implied endorsement of such products.

ABSTRACT

The costs and performance potential were assessed for the simultaneous use of NO_x control systems applied in various combinations and at various control levels on 11 stationary sources. NO_x control systems which were studied included combinations of low NO_x burners (LNB), selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). The stationary sources, totalling 11 different installations, include refinery process heaters and industrial boilers of various sizes and types, a carbon monoxide boiler, and a glass melting furnace.

Primary emphasis was on NO_x reduction costs and corresponding applicability of various control strategies as applied to major emission sources for a range of sizes and equipment operating conditions. In addition, the cumulative performance potential of each combination control option was assessed.

It was concluded that generally the applicability of a combination of NO_x controls is feasible, but the cost-effectiveness is unique for each unit examined. In addition, overall system complexity increases as denitrification systems are added. However, some general trends were detected: 1) application of NO_x controls to refinery heaters is, on the average, less costly than for industrial boilers; 2) application to larger units is, on the average, less costly than for smaller units; 3) the combination of LNB + SCR is generally competitive with SCR at control levels between 80% to 90% NO_x reduction; 4) from 70% to 90% reduction, SCR is usually more cost-effective; 5) at 70% NO_x removal LNB + SNCR is more attractive; and 6) at 50% and 40% NO_x reduction, SNCR and LNB, respectively, have the lowest cost.

Capital investment cost estimates are provided in mid-1981 dollars and reflect estimated retrofit complexity factors for the various installations. Annual control costs in terms of dollars per pound NO_x removed and dollars per million Btu thermal input are also reported.

ACKNOWLEDGEMENTS

Contributions were made to the study in the form of data and information by numerous individuals and organizations to whom appreciation is gratefully extended. However, assembly of the data, assessments, and conclusions drawn are those of the authors. The assistance and guidance of members of the California Air Resources Board staff, especially the Project Officer, Mr. Jack Paskind, Manager, Emissions Control Technology Research Section, as well as Mr. Manjit Ahuja, Air Resources Engineer, are acknowledged.

Contributions in the form of operating information and site data were provided by operators of the refinery equipment and industrial boilers.

Information on control systems and applications was provided by Joy Industrial Equipment Company, the John Zink Company, Coen Company, Inc., the Forney Engineering Company and the Gas Research Institute..

This report was submitted in fulfillment of Contract Number A9-117-30, "Assessment of Simultaneous Use of NO_x Control Systems on Stationary Sources in California", by The Aerospace Corporation, under the sponsorship of the California Air Resources Board. Work was completed as of 30 November 1981.

CONTENTS

CONTENTS (Cont'd)

PAGE

LIST OF FIGURES

LIST OF FIGURES (Cont'd)

LIST OF TABLES

LIST OF TABLES (Cont'd)

LIST OF TABLES (Cont'd)

CONVERSION TABLE

British	Metric
1 inch	2.540 centimeters
1 foot	0.3048 meter
1 cubic foot	28,316 cubic centimers; 0.028316 cubic meters
1 gallon	3.785 liters
1 pound	454 grams
1 ton (short)	0.9072 metric ton
1 pound per square inch	0.0703 kilogram per cubic centimeter
1 pound per square foot	0.1602 gram per cubic centimeter
1 British thermal unit (Btu)	252 calories
1 pound per million Btu	0.430 gram per million joules; 1.80 grams per million calories
1 Btu per pound	2.324 joules per gram; 0.555 calories per gram
1 grain	64.8 milligrams
1 grain/SCF	2.29×10^3 milligrams/Nm^3

GLOSSARY

LNB	low NO_x burner
SNCR	selective non-catalytic reduction also referenced in the literature as Thermal $DeNO_x$ as patented by Exxon Research and Engineering Company
SCR	selective catalytic reduction
CARB	California Air Resources Board
CO	carbon monoxide
NO_x	oxides of nitrogen (NO and NO_2)
MMBtu	million British thermal units
^oC	degrees Celsius
^oF	degrees Farenheit
NH_3	ammonia
NH_4HSO_4	ammonium bisulfate
SO_2	sulfur dioxide
SO_3	sulfur trioxide
MW_e	megaWatt electrical equivalent
$/lb	dollars per pound
SCFM	standard cubic feet per minute
ACFM	actual cubic feet per minute
CFH	cubic feet per hour
nM^3	normal cubic meters
O&M	operating and maintenance
ppm	parts per million
FCC	fluid catalytic cracker

1.0 INTRODUCTION AND SUMMARY OF FINDINGS

1.1 Scope of Study

The objective of this study was to determine the applicability, performance potential and cost of various methods of NO_x control to a variety of stationary sources representing a range of refinery heaters and boilers, industrial boilers and a glass melting furnace. Low NO_x burners (LNB), selective non-catalytic reduction (SNCR), also designated as thermal DeNO_x, and selective catalytic reduction (SCR) were the three methods considered. The stationary sources selected for the study were based on stationary source and size guidelines provided by the Research Staff, California Air Resources Board (CARB). Control strategies included employing each method alone and in combination with the others.

Information was obtained from the operators of the various stationary equipments. Information on control system characteristics was obtained by recent discussions with various developers, suppliers and users of the hardware and also drew heavily on the detailed survey conducted by The Aerospace Corporation and reported in Reference 1-1.

The analysis was based on the stationary sources operating at normal or observed load. In some cases extrapolations were extended to design load, 75% of design load, or 50% of design load. Similarly, cost-effectiveness estimates ($/lb NO_x removed) were determined for design conditions and adjusted for observed or expected operating load. In addition to the effect of load on cost-effectiveness, the effect of exhaust gas reheat (where required for SCR catalyst operation) and a comparison of control costs of gas versus oil fuels were made.

1.2 Description of Sources

The stationary sources included five refinery heaters rated from 65 to 435 MMBtu/hr, five industrial boilers rated from 4 to 336 MMBtu/hr, one CO boiler rated at 275,000 lb/hr steam, and one 200 ton per day container (flint) glass furnace. Table 1-1 is a summary of the stationary sources and their respective emission characteristics based on the use of primarily gaseous fuels which are currently in use and considered in the study guidelines to be in continued use in the future.. Because of the diversity of heater and boiler designs and sizes that are located in the Los Angeles Basin, it cannot be stated that any of the equipment studied can be considered "typical". However, an attempt was made to encompass the range of equipment sizes and determine cost trends, if any, based on this parameter. In that sense it is believed the resultant evaluation is representative of the control costs that could be incurred based on the trends developed in the study.

1.3 Description of Technology

The technology for combined NO_x controls was based on individual technology operating experience in U.S. and Japan (References 1-1 and 1-2). Desired technical performance is generally achievable given required space and configurations.

TABLE 1-1
NO_x EMISSION CHARACTERISTICS OF STATIONARY SOURCES
BURNING GASEOUS FUELS

EQUIPMENT	SIZE, MMBtu/HR	UNIT DESIG. THIS RPT.	FUEL[a]	NO. OF BURNERS	OPERATION HRS/YR	NO_x EMISSIONS LB/HR AS NO_2			REHEAT, °C	REHEAT EMISSIONS, LB/HR		TOTAL NO_x EMISSIONS LB/HR	
						CURRENT LOAD		LOAD 100%		CURRENT LOAD	100% LOAD	CURRENT LOAD	100% LOAD
						%	NO_x						
REFINERY HEATER	65	A	R	24	7884	89	6.7	7.5	NONE[b]	N/A[c]	N/A	6.7	7.5
	93	B	R	72	8330	100	11.9	11.9	89	0.6	0.6	12.5	12.5
	115	C	R	12	7534	90	23.7	26.3	NONE[b]	N/A	N/A	23.7	26.3
	164	D	R	48	8235	88	34.0	38.6	22	0.22	0.25	34.2	38.8
	435	E	R	136	8059	80	71.2	89.0	NONE[b]	N/A	N/A	71.2	89.0
INDUSTRIAL BOILER	4	F	N	1	5944	100	0.4	0.4	128	0.04	0.04	4.4	4.4
	22	G	N	1	5843	52	1.9	3.6	78	0.1	0.2	2.0	3.8
	22	H	O	1	5843	52	5.5	10.6	78	0.1	0.2	5.5	10.8
	150	I	O	1	7884	48	9.4	19.6	68	0.3	0.7	19.9	20.3
	336	J	N	4	8376	54	36.9	68.3	83	1.1	2.1	38.0	70.4
CO BOILER	582	K	R	8	8400	45	181.1	402.4	NONE[b]	N/A	N/A	181.1	402.4
GLASS FURNACE	43	L	N	NAV[d]	8760	100	38.4	38.4	NONE[b]	N/A	N/A	38.4	38.4

[a] R = REFINERY GAS, N = NATURAL GAS, O = NO. 2 FUEL OIL
[b] REHEAT NOT REQUIRED
[c] NOT APPLICABLE
[d] NOT AVAILABLE

In addition to the three major control technologies considered in this study as applicable to refinery heaters, industrial furnaces and glass melting furnaces, it is recognized that a number of potentially other efficient alternative NO_x control strategies are applicable to glass melting furnaces. In many cases, these methods are likely to be implemented before post-combustion controls and would include process changes such as modifications to burner design, modification to excess air levels, and electric boosting. These process changes were not within the scope of the study and were therefore not included in the analysis.

1.3.1 Low NO_x Burners

Low NO_x burners (LNB) are widely used in Japan on utility and industrial boilers and on other industrial combustion equipment. The NO_x reduction is influenced by the burner configuration, size, type of fuel burned (oil, gas, coal, and fuel nitrogen content), and type of combustion modifications (CM) implemented prior to the use of LNB. For example, with one type of LNB burning heavy oil NO_x was reduced from 18 to 42% when operated without other CM techniques in use. When 40% reduction was achieved by other types of CM, such as flue gas recirculation (FGR), staged combustion, water injection, or a combination of these, further reductions of 10 to 20% were achieved by the addition of an LNB, for a total removal of 40 to 50% (Reference 1-1).

Recent U.S. and Japanese refinery experience indicates that certain low NO_x burners can reduce thermal NO_x emissions by 40% - 50% (References 1-1, 1-3). For gaseous fuels this results in an overall 40% - 50% reduction. In liquid fuels, because the fuel nitrogen component is virtually unaffected, the overall reduction rate is less.

1.3.2 Selective Noncatalytic Reduction

Ammonia reacts selectively with NO at approximately 1000°C (1830°F), forming N_2 and H_2O. As in the case of selective catalytic reduction SCR (described later), selective non-catalytic reduction (SNCR) requires the presence of a small amount of O_2 for the reaction to occur. Exxon Research and Engineering Company has patented the application of non-catalytic reduction as a NO_x control process, and is also referenced as Thermal $DeNO_x$.

Tests have been reported to show that the temperature interval, or "window", over which appreciable NO_x reduction occurs is approximately 100°C (180°F) and the reduction levels are a function of the NH_3 to NO_x mole ratio. The location of the temperature window which is nominally 1000°C can be lowered by the introduction of hydrogen. Depending on the amount of H_2 introduced (with H_2 to NH_3 ratios as high as 2), the reaction temperature is reduced by approximately 250°C (450°F).

Laboratory tests have shown that 80 to 90% NO_x reduction can be achieved with ammonia injection rates of 1.1 to 1.6 NH_3/NO_x mole ratios. However, for full-scale equipment applications, the removal rate appears to be limited to approximately 65%, with 50% being typical value for a constant load source and perhaps 40% for a source with a variable load (Reference 1-1). Temperature uniformity, NH_3 distribution and residence time at temperature are the key parameters affecting performance.

By-product emissions include unreacted ammonia. Concentrations in the exhaust stream resulting from the 1.5 NH_3/NO_x mole ratio required to achieve 50% reduction may be in the range of 30 to 50 ppm. The NH_3 has the potential for forming NH_4HSO_4 where SO_3 is present and condensing at temperatures of approximately 215°C (425°F) (Reference 1-1). Other emissions such as cyanides and nitrates have been reported, averaging 2 and 10 ppm, respectively (Reference 1-4). However, no correlation was reported between the amount of ammonia injected and the emission levels of these pollutants, thereby suggesting that the cyanide and nitrates may not be a by-product of the NH_3 injection process.

Full-scale use of SNCR has been applied in Japan, with approximately 11 units being reported, ranging from 190 to 1320 MMBtu/hr thermal input. These units include industrial and utility boilers, CO boilers, and crude oil heaters. Generally they are operated during pollution alerts only; two were demonstration units. A full-scale installation in the U.S. on a 50 MMBtu/hr oil field steam generator has been reported, with up to 65% removal at a mole ratio (NH_3/NO_x) of 1.5 (Reference 1-1). It has also been applied in the U.S. by KVB and Fletcher Oil, Carson, CA on refinery heaters. Details of the results and performance of the process are not currently available.

On the basis of the performance reported above for similar units, the feasibility for Thermal $DeNO_x$ achieving a 50% reduction has been shown for refinery heaters and steam boilers (References 1-1, 1-3).

Limitations on NO_x reduction exist with varying load conditions and multiple NH_3 injection grids may be required. To locate the NH_3 injection sites, a thorough thermal profile mapping of each NO_x source is required. Since this type of data normally does not exist for refinery heaters and industrial boilers, it was assumed for the equipment discussed in this report that suitable temperature profiles exist for placement of NH_3 injection grids in accessible locations.

1.3.3 Selective Catalytic Reduction (SCR)

The NO_x from stationary sources is virtually all nitric oxide (NO) and can be reduced to N_2 and H_2O by ammonia in the presence of certain base metal catalysts. In order to achieve a 90% reduction, temperatures in the range of 260 to 380°C (500 to 715°F) are required in the reactor with an NH_3 to NO_x ratio of 0.9 to 1.1 (References 1-1, 1-5). Small quantities of oxygen in amounts normally present in the emissions as a result of excess air (approximately 1%) in the combustion process are needed.

To determine the effect of NO_x removal rate on cost, SCR reactors in this study have been sized so that 50 to 90% NO_x removal can be achieved either alone or for use with other control options.

In some stationary sources, reheat of the exhaust gas is required to achieve the minimum effective temperature for optimum NO_x removal rates with catalysts currently in use. In those cases, recovery of a major fraction of the reheat energy can be effected through a heat exchanger downstream of the SCR unit thereby offsetting some of the fuel and capital cost penalties incurred with the reheating. It must be noted that this study was aimed at NO_x control and not energy conservation. Therefore, no attempt was made to include exhaust gas heat recovery equipment and credits to offset the cost of NO_x control in those specific equipments where gas temperatures were high enough for SCR and reheat was not required.

Criteria used for catalyst bed sizing are summarized in Table 1-2 and include type of fuel, flue gas temperature, SO_2 emissions, and particulate loading. In general, for a gas-fired unit under conditions of optimum flue gas temperature and negligible SO_2 and particulate emissions, a normal space velocity of approximately 6000 hr^{-1} (dry basis) could be considered. For cases in which sub-optimum temperatures are encountered either independently or in combination with SO_2 and particulate loading, a lower space velocity would be required as shown in Table 1-2. Oil-firing necessitates a lower space velocity due to associated SO_2 emissions and particulate loading. Flue gas temperatures for optimum catalyst performance were considered to be in the range of 350 to 400°C and the low operating temperatures are those between 255 and 260°C. As was noted above, tradeoffs between the cost of increasing the reheat temperature and the associated equipment and fuel costs versus the corresponding reduction in catalyst volume (increased space velocity) were not conducted.

1.3.4 Combinations of Control Technologies

In combining controls the cumulative effect of each control system is considered with no resultant degradation of individual system performance levels providing adequate space and appropriate conditions conducive to each system are available. Although space is assumed to be present, installation is not necessarily assumed to be without problems and some relocation of existing equipment may be needed. The combined control options that were considered are: LNB alone, SNCR alone, SCR alone, LNB with SNCR,LNB with SCR, SNCR with SCR, and LNB with SNCR plus SCR.

There does not appear to be any technical reason to preclude combining multiple NO_x control systems. However, cost considerations make some combinations unattractive. In addition, the overall complexity of the control system is increased by utilizing multiple systems.

1.4 Cost Estimates

A graphical representation of general NO_x removal cost-effectiveness trends for combined controls is presented in Figure 1-1. This report also presents the effect of load, fuel (gas versus oil) and reheat on control system cost-effectiveness.

TABLE 1-2

CATALYST BED SIZING CRITERIA AS RELATED TO REFINERY HEATER AND INDUSTRIAL BOILER EMISSION CHARACTERISTICS

FUEL	FLUE GAS CONDITIONS			SPACE VELOCITY,[d] NOMINAL (HR^{-1})	APPLICABLE EQUIPMENT, DESIGNATION[e]
	TEMP[a]	SO_2[b]	PARTICULATES[c]		
GAS	OPTIMUM	NONE	NONE	6200	A
GAS	LOW[f]	NONE	NONE	4200	B, C, D, E, F, J
OIL	LOW	SOME	SOME	2400	H, I
GAS	LOW	SOME	SOME	2500	K

[a] OPTIMUM = 350 - 400°C
LOW = 255 - 260°C

[b] SOME = 5 - 200 ppm

[c] SOME = 0.01 - 0.3 GRAINS/STANDARD CUBIC FEET

[d] BIANNUAL CATALYST REPLACEMENT. SPACE VELOCITY IS ON A DRY BASIS

[e] DESIGNATION - THIS REPORT

[f] TEMPERATURE BASED ON MINIMIZING REHEATER AND HEAT RECOVERY EQUIPMENT AND FUEL REQUIREMENTS

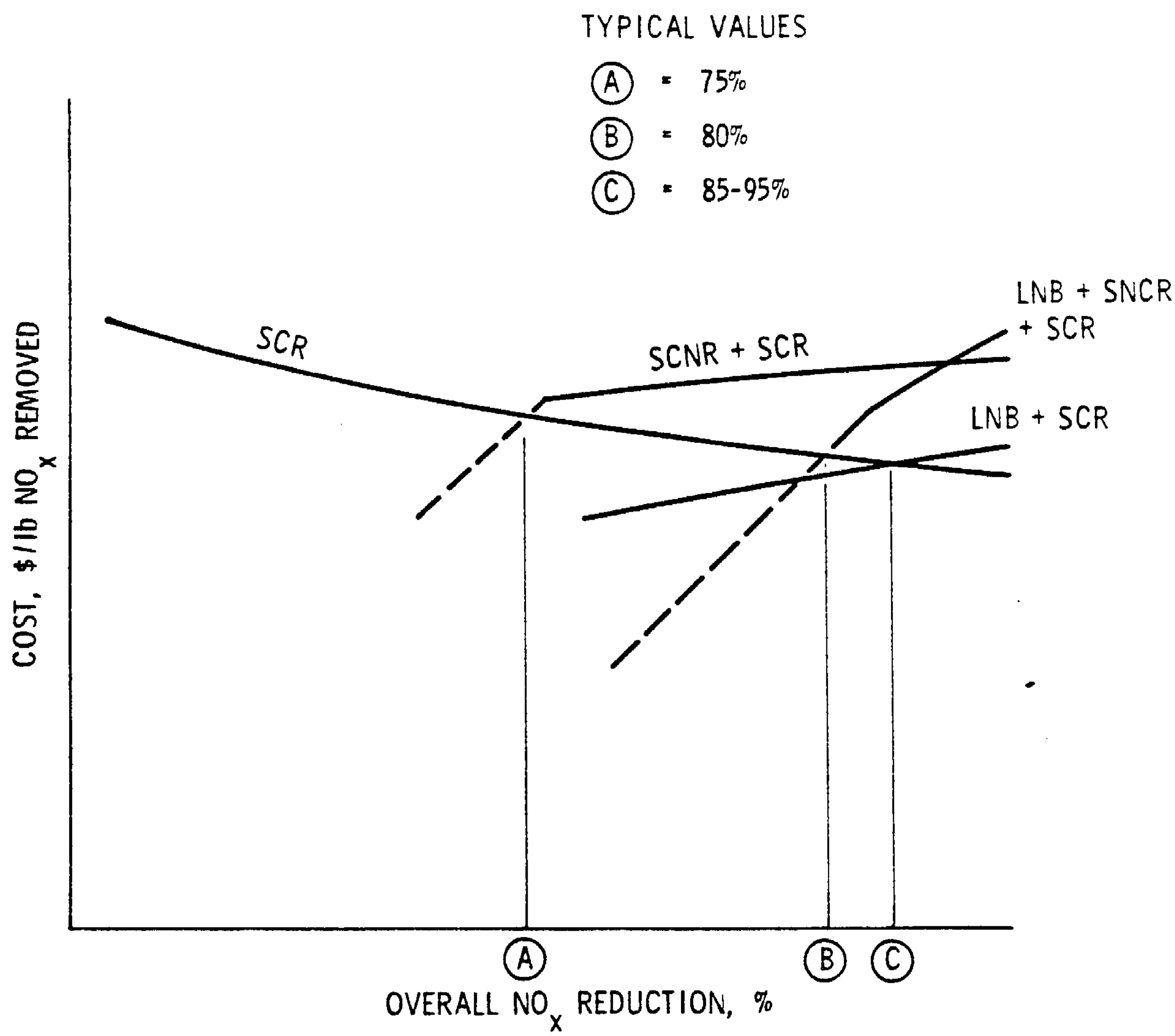


Figure 1-1 General NO_x Removal Cost-Effectiveness Trends as a Function of Overall NO_x Reduction

The costs reported do not reflect any tax savings that a company may incur from the installation of pollution control equipment such as investment tax credits, deduction for interest expense or depreciation. All of these factors would tend to reduce the net cost of the equipment to the company. Also the opportunity costs such as those resulting from lost production during retrofit shutdown were not included. This was considered a reasonable approach because the control equipment buildup was assumed to be incurring in parallel with normal equipment operation and installed or connected during normal maintenance shutdown periods. However, if operational schedules do not permit such an approach, lost production should be considered.

SCR is equivalent in cost to LNB plus SCR at points B and C, which correspond to overall NO_x removal rates. As an example, for reductions less than B, LNB plus SCR has a lower NO_x removal cost than any other combination or option. For reductions greater than C, SCR is the least costly option in terms of NO_x removal. It is apparent that SNCR plus SCR, and LNB plus SNCR plus SCR are not cost competitive.

Although an option may have a low NO_x removal cost, there may be other reasons which would make another slightly more costly alternative more desirable; i.e., there may be some advantage to combination LNB plus SCR for removal rates greater than C due to the capability of LNB to prevent total loss of NO_x control if the SCR system is taken off the line for catalyst replacement or for other reasons.

An average cost index of combined NO_x control systems relative to SCR (alone) at 90% reduction is shown in Figures 1-2 and 1-3 for refinery heaters and industrial boilers. The combinations of systems that achieve specific control levels are shown.

In the 80-90% range, the combination of LNB plus SCR is comparable to the cost of SCR installations (Table 1-5). For less than 80%, other combinations or individual controls are less costly than an equivalent sized SCR reactor.

In general, NO_x control on boilers is more cost-effective relative to SCR than heaters (Figure 1-2). Also, larger units are more cost-effective than smaller units (Figure 1-3).

The effects of reheat and reheat recovery on costs for industrial boilers are illustrated in Figure 1-4 ($/lb vs. size). Heaters are less consistent in terms of cost-effectiveness as a function of size.

Table 1-3 depicts the cost of NO_x reduction with the use of low NO_x burners at 100% load. All costs are given in 1981 dollars. Total quantities of NO_x removed, capital cost, annual cost, and cost-effectiveness in terms of dollars per pound of NO_x removed and dollars per million Btu's are presented. These costs are based on an estimated 40% NO_x removal rate of the low NO_x burners relative to conventional burners. In the case of the 22 MMBtu/hr industrial boiler which fires either natural gas or No. 2 fuel oil and the 150 MMBtu/hr Boiler which burns oil, it was estimated that the LNB would cause a 40% reduction

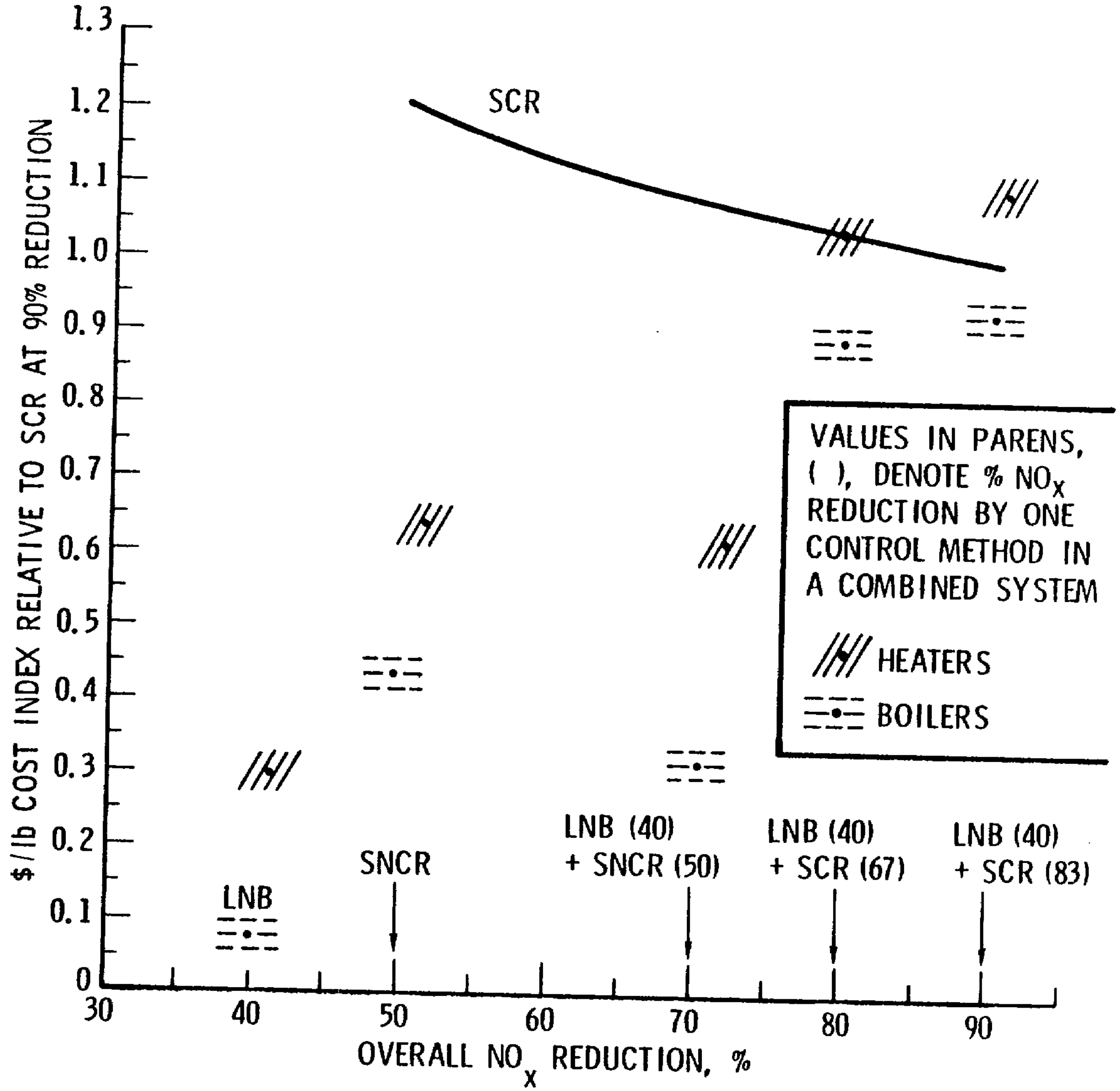


Figure 1-2 Relative Cost of NO_x Removal as a Function of Overall Reduction for Heaters and Boilers Employing Various Combinations of Controls

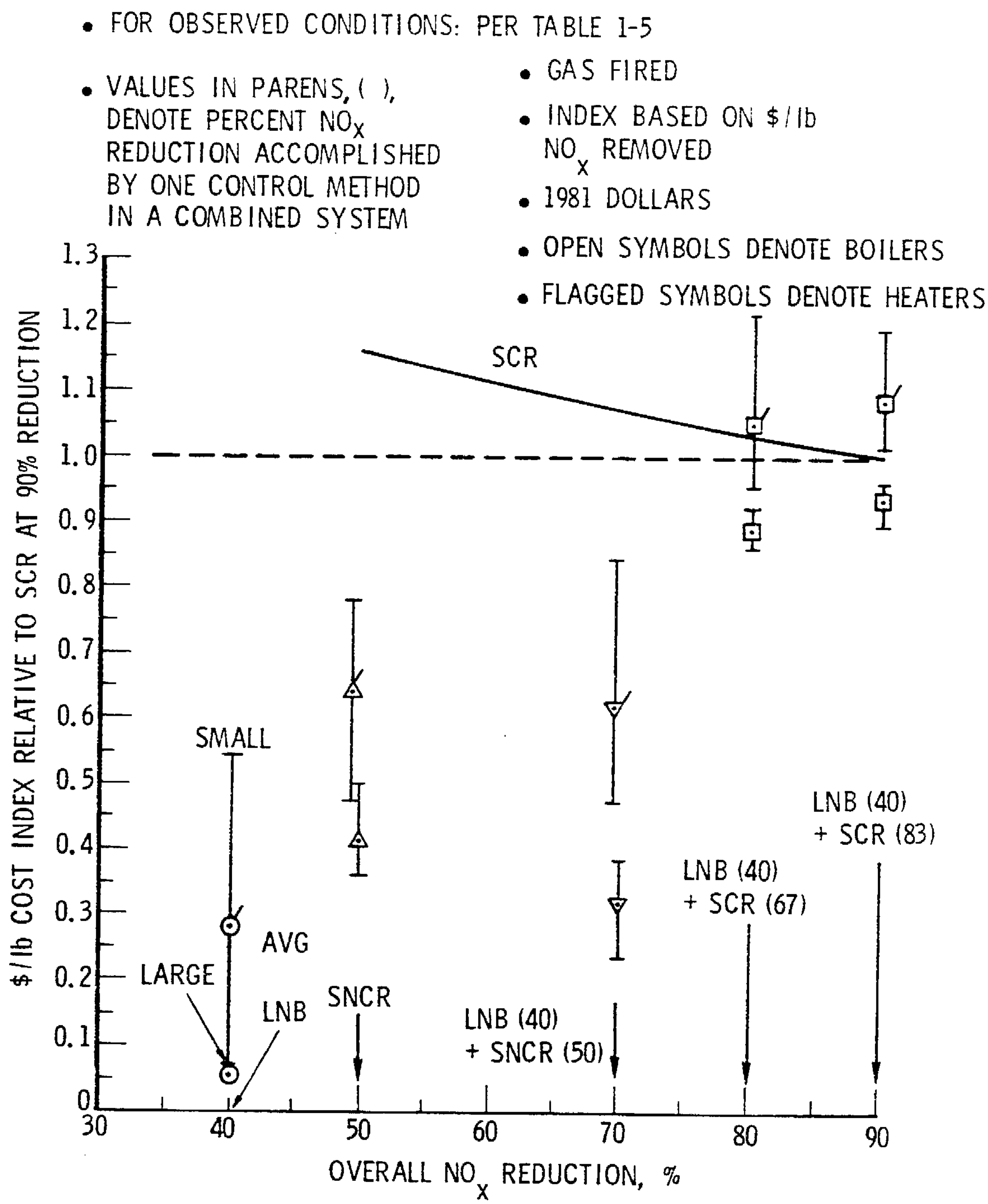


Figure 1-3 Cost of Control Indexed to SCR at 90% Reduction for Combinations of Controls

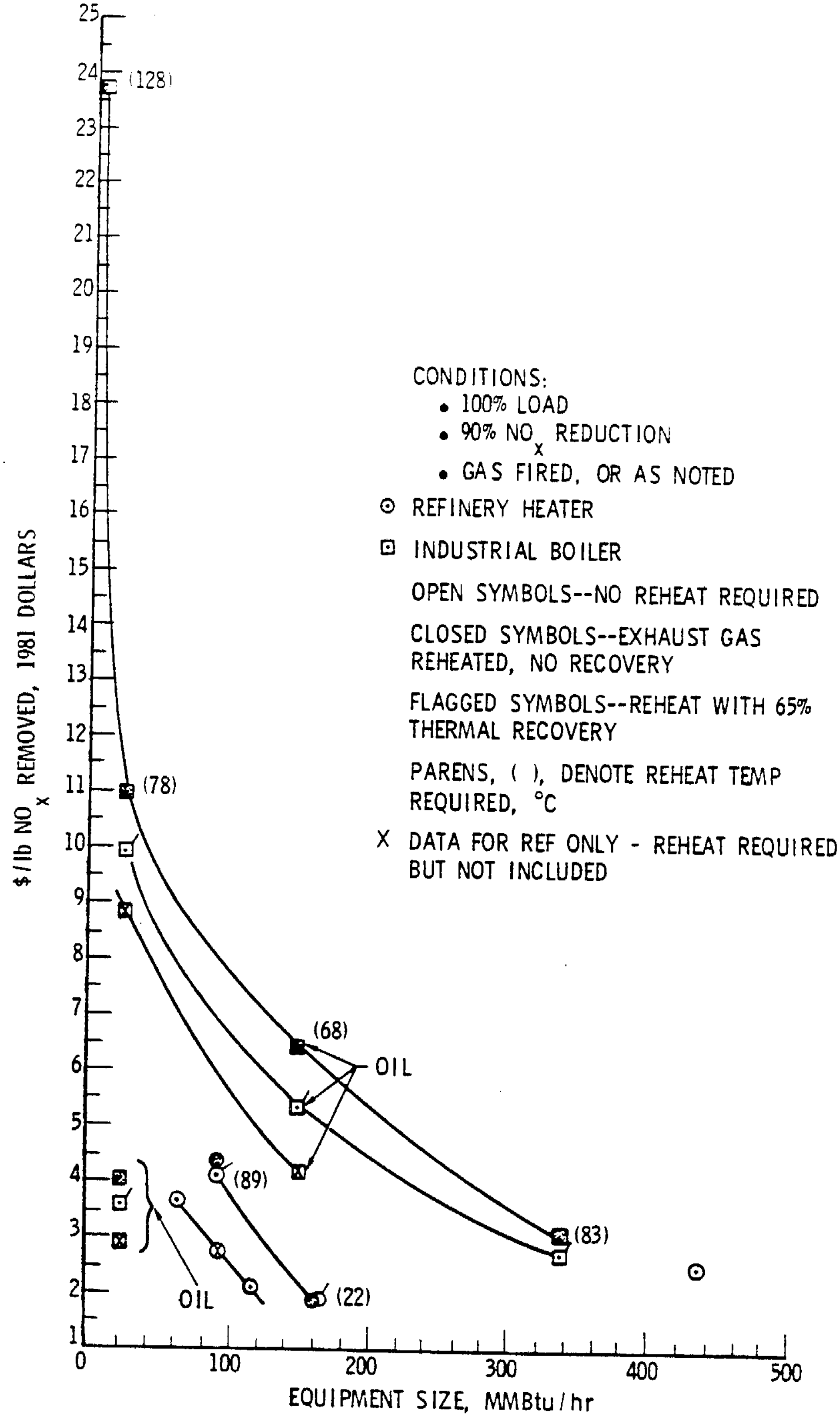


Figure 1-4 Cost of NO_x Removal Using SCR on Refinery Heaters and Industrial Boilers (1981 Dollars)

TABLE 1-3

COST OF NO_X REDUCTION WITH USE OF LOW NO_X BURNERS WITH GASEOUS FUELS AT 100% LOAD (1981 DOLLARS)

EQUIPMENT	UNIT DESIG	SIZE MMBTU/HR	HRS/YR OPERATED	NO_x EMISSIONS LB/YR	BURNERS QTY	BURNERS CAPITAL COST, $[a]	BURNERS TOTAL CAPITAL INVESTMENT, $	NO_x[b] REMOVED LB/HR	ANNUAL COST, $	$/LB NO_x	$/ MMBTU
REFINERY HEATER	A	65	7884	7.5	24	108,400	145,400	3.0	46,500	1.97	0.091
	B	93	8330	11.9	72	148,600	199,200	4.8	63,800	1.60	0.082
	C	115	7534	26.3	12	28,700	38,500	10.5	12,300	0.16	0.014
	D	164	8235	38.6	48	100,200	134,400	15.4	43,000	0.34	0.032
	E	435	8059	89.0	136	280,500	376,100	35.6	120,400	0.42	0.034
INDUSTRIAL BOILER	F	4	5944	0.40	1	2,900	3,900	0.16	1,240	1.30	0.052
	G	22	5843	3.6	1	8,200	10,900	1.5	3,500	0.40	0.027
	H	22[c]	5843	10.6	1	8,200	10,900	1.0[d]	3,500	0.61	0.027
	I	150[c]	7884	19.6	1	18,200	24,400	3.5[d]	7,800	0.28	0.006
	J	336	8376	68.3	4	63,600	85,200	27.3	27,300	0.12	0.010
CO BOILER	K	582	8400	402.4	8	150,200	161,000	161.0	51,600	0.038	0.033

[a] INCLUDING 72% RETROFIT FACTOR

[b] ESTIMATED 40% NO_x REMOVAL (THERMAL NO_x) RELATIVE TO EXISTING CONVENTIONAL BURNERS

[c] NO. 2 FUEL OIL

[d] EST. 40% THERMAL NO_x REDUCTION. EST. 55% FUEL NO_x NOT AFFECTED

in thermal NO_x emissions while leaving the estimated 55% fuel NO_x in the emissions unaffected. Cost-effectiveness of low NO_x burners ranges from \$0.16-1.97/lb NO_x removed for heaters, \$0.12-1.30/lb NO_x removed for boilers and \$0.38/lb NO_x removed for the CO boilers. In general, the higher cost applies to the smallest units and the lower costs to the larger installations.

The cost for SCR installations is summarized in Table 1-4 and it is based on a 90% NO_x removal rate, also at 100% load. In addition, where exhaust gas reheat is necessary to meet catalyst temperature requirements, and can be effectively recovered (based on a 65% thermal recovery), the credit from reheat recovery is shown in the column following the amount of reheat required. A credit averaging about \$0.80/lb NO_x for units requiring about 80°C of reheat is shown. Also, the simple payback period for heat recovery equipment is presented.

The range of costs for 90% SCR control is \$1.95-3.95/lb NO_x removed for heaters and \$3.68-23.75/lb NO_x removed for boilers. In general, the lower costs apply to the larger installations. The cost for the CO boiler is \$3.60/lb, and for a 200 TPD flint glass melting furnace is \$1.45/lb NO_x.

Table 1-5 summarizes the cost of combined NO_x control systems (including SNCR alone). Values are computed on the basis of observed operating load (at the time of the study) which varies for each unit, and costs depend on levels of secondary controls as indicated. The cost of SCR (alone) at the corresponding control level is also shown for comparison. The data support the information discussed earlier and presented in Figures 1-2 and 1-3 regarding the costs of various methods and combinations relative to SCR.

Table 1-6 which is cross-indexed to Figure 1-1, compares the cost-effectiveness of combined control systems with SCR at observed operating loads.

The performance matrix represented in Table 1-7 summarizes the previous tables and graphs and shows the degree to which each control option can be cost-effectively utilized for the various installations examined.

TABLE 1-4 COST OF SCR INSTALLATIONS FOR NO_x CONTROL

EQUIPMENT	SIZE	UNIT DES.	SCR 90% NO_x REMOVAL, 100% LOAD, 1981 DOLLARS[a]						TOTAL[f] EMISSIONS W/O CONTROLS	REHEAT °C	SAVINGS FROM REHEAT REC., $/lb	HEAT REC. SIMPLE PAYBACK PERIOD, YR
			CAP COST, $	CAP INV., $	RETROFIT FACTOR, %		$/lb[b]	$/MMBtu[b]				
					THIS REPORT	OTHER[e]						
REFINERY HEATER	65	A	322,100	480,500	15	23	3.65	0.38	7.5	NONE	N/A	N/A
	93	B	595,800	892,000	15	103	4.22	0.51	12.5	89	0.16	2.1
	115	C	544,800	815,900	15	27	2.08	0.43	26.3	NONE	N/A	N/A
	164	D	793,400	1,193,900	15	36	1.92	0.42	38.8	22	0.01	2.1
	435	E	1,806,600	2,655,600	15	12	2.66	0.49	89.0	NONE	N/A	N/A
INDUSTRIAL BOILER	4	F	103,500	153,900	15	55	23.75	2.35	0.44	128	NO	>8
	22	G	322,100[d]	451,000	15	70	9.86	1.54	3.8	78	1.07	4.8
	22	H[c]	322,100	451,000	15	70	3.59	1.57	10.8	78	0.43	4.8
	150	I[c]	1,025,500	1,542,700	15	59	5.32	0.65	20.3	68	1.25	1.0
	336	J	1,752,700	2,630,400	15	20	2.69	0.51	70.4	83	0.34	1.7
CO BOILER	582	K	6,137,300	9,256,000	15	18	1.69	1.05	402.4	NONE	N/A	N/A

[a] 100% LOAD FOR THE ANNUAL OPERATING HOURS SHOWN IN TABLE 1-3

[b] WITH REHEAT AND 65% REHEAT RECOVERY

[c] NO. 2 FUEL OIL

[d] DESIGNED FOR FUEL OIL OPERATION

[e] SEE PARAGRAPH 2.2.1, EQUIVALENT TO 15% USED IN THIS REPORT

[f] INCLUDING NO_x FROM REHEAT

TABLE 1-5 COST OF COMBINED NO_x CONTROL SYSTEMS

(1981 DOLLARS)

EQUIPMENT	DESIG	SIZE, MMBTU/HR	LOAD, %	REHEAT[a]/ RECOVERY	SNCR [b]		SCR	LNB(40)+ SNCR(50) [f]		SCR	LNB(40)+ SCR (67)		SCR	LNB(40)+ SCR (83)		SCR	HOURS/ YR
					%	$/lb	$/lb	%	$/lb	$/lb	%	$/lb	$/lb	%	$/lb	$/lb	
REFINERY HEATER	A	65	89	NOT REQ.	50	3.10	5.10	70	3.50	4.40	80	5.00	4.20	90	4.90	4.10	7881
	B	93	100	89°C/NO	50	2.20	5.40	70	2.50	4.90	80	4.90	4.70	90	5.00	4.60	8310
			72	89°C/NO	50	2.10	6.50	70	2.50	5.90	80	5.90	5.70	90	6.00	5.60	8330
	C	115	90	NOT REQ.	50	1.80	2.90	70	1.40	2.50	80	2.20	2.40	90	2.30	2.30	7534
	D	164	88	22°C/NO	50	1.50	2.70	70	1.30	2.40	80	2.30	2.30	90	2.40	2.20	8235
	E	435	80	NOT REQ.	50	1.40	2.90	70	1.30	2.80	80	2.60	3.00	90	2.80	2.70	8059
INDUSTRIAL BOILER	F	4	100	128°C/NO	50	13.00	>30	70	10.20	28.50	80	22.50	27.25	90	23.50	26.00	5944
	G	22	52	78°C/NO	50	6.90	18.50	70	5.40	17.30	80	14.50	16.75	90	14.80	16.00	5843
	H	22[e]	52	78°C/NO	50	2.60	7.00	70	---	6.20	80	5.80	6.00	90	5.10	5.80	5843
	I	150[e]	100	68°C/65%	50	1.85	6.50	70	---	5.80	80	5.50	5.60	90	5.30	5.30	7884
	J	336	54	83°C/NO	50	1.60	4.60	70	1.40	4.50	80	3.90	4.50	90	4.20	4.50	8376
CO BOILER	K	582	45	NOT REQ.	50	0.86	4.50	70	0.67	3.90	80	3.70	3.70	90	3.50	3.40	8400
GLASS FURNACE	L	43	100	NOT REQ.	50	0.90	1.90	N/A[c]	N/A	N/A	80[d]	1.84	1.50	90	1.85	1.46	8760

[a] NO. REHEAT REQUIRED FOR SNCR & LNB.. REHEAT REQD ONLY FOR SCR AS INDICATED.

[b] APPLICABILITY MUST BE DETERMINED BY TEST. THE PRESENCE OF APPROPRIATE CONDITIONS FOR USE OF SNCR MUST BE DETERMINED EXPERIMENTLY.

[c] CONSIDERED NOT APPLICABLE BECAUSE OF THE UNCERTAINTY OF THE SUITABILITY OF LOW NO_x BURNERS.

[d] 50% SNCR & 60% SCR

[e] NO.2 FOR FUEL OIL; ALL OTHERS GASEOUS FUEL

[f] THE VALUES IN PARENS () DENOTE THE PERCENT NO_x REMOVED BY THE CORRESPONDING CONTROL MEASURE

TABLE 1-6

COMPARISON OF COMBINED NO_x CONTROL SYSTEMS WITH SCR

EQUIPMENT	UNIT DESIG	SIZE, MMBTU/HR	OPERATING LOAD, %	CROSS-OVER RELATIVE TO SCR[a]					
				SNCR + SCR (A)[b]		LNB + SNCR + SCR (B)		LNB + SCR (C)	
				%	$/LB	%	$/LB	%	$/LB
REFINERY HEATER	A	65	89	65	4.60	75	4.20	65	4.60
	B	93	100[c]	75	4.70	80	4.60	75	4.80
		93	72[c]	70	5.90	80	5.70	70	6.00
	C	115	90	65	2.60	80	2.40	90	2.30
	D	164	88[c]	65	2.40	80	2.20	80	2.20
	E	435	80	75	2,90	85	2.80	90	2.80
INDUSTRIAL BOILER	F	4	100	75	25.00	90	26.00	>100	23.00
	G	22	52[c]	75	17.00	90	16.50	95	15.70
	H	22[d]	52[c]	75	6.20	80	6.10	90	5.70
	I	150[d]	100[c]	75	5.70	80	5.40	100	5.20
	J	336	54[c]	80	4.50	90	4.50	95	4.40
CO BOILER	K	582	45	80	3.70	90	3.50	95	3.40

a Rates at which cost of Combination Controls begin to exceed SCR, See Fig 1-1
b Ref Fig 1-1
c With Reheat
d Fuel Oil

TABLE 1-7. SUMMARY OF POTENTIAL COST EFFECTIVE NO_x REDUCTION LEVELS USING SINGLE AND MULTIPLE NO_x CONTROL METHODS

UNIT DESIGN	SIZE \ CONTROL OPTION	LNB	SNCR	SCR	LNB + SNCR	LNB + SCR	SNCR + SCR	LNB + SNCR + SCR
	REFINERY HEATERS							
A	65 MMBtu/Hr	40[a]	50	70-90	70	X[b]	X	X
B	93 MMBtu/Hr	40	50	70-90	70	70-80	80	X
C	115 MMBtu/Hr	40	50	80-90	70	70-90	X	X
D	164 MMBtu/Hr	40	50	80-90	70	70-90	X	X
E	435 MMBtu/Hr	40	50	80-90	70	70-90	X	85
	INDUSTRIAL BOILERS							
F	4 MMBtu/Hr	40	50	X	70	70-90	X	X
G	22 MMBtu/Hr (gas)	40	50	X	70	70-90	X	X
H	22 MMBtu/Hr (oil)	18	50	80-90	60	60-90	X	X
I	150 MMBtu/Hr (oil)	18	50	60-90	60	60-90	X	80-85
J	336 MMBtu/Hr	40	50	90	70	70-90	X	85-90
K	582 MMBtu/Hr CO Boiler	40	50	85-90	70	70-90	X	85-90
L	Glass Furnace, 200 TPD	N/A[c]	50	50-90	N/A	N/A	X	N/A

[a]Overall NO_x Reduction, %

[b] X Denotes Other Methods are Less Costly to Achieve Designated Control Levels

[c]N/A Denotes the Method to be Not Applicable for Technical or Operational Reasons

1.5 Findings

The results of this study has shown that certain combinations of NO_x control systems are reasonable from a cost perspective; however, limitations may exist in utilizing a combination approach involving the increased complexity of operating more than one system. For example, physical and operational integration of separate control and instrumentation systems is necessary for the optimum combination of any of the technologies. Consequently, it is recommended that problems of this nature be quantitatively assessed in future pilot/test programs. Significant findings from this study are:

(1) For each control option and type of units examined in this study, the cost of NO_x control is affected by the type of emission source, capacity factor, fuel burned, necessity for flue gas reheat, and retrofit considerations. Thus, a typical cost for NO_x removal in terms of \$/lb NO_x cannot be established.

(2) In general, NO_x control costs for refinery heaters are less costly in terms of \$/lb NO_x removed than industrial boilers.

(3) NO_x control installations on larger refinery heaters or industrial boilers are generally more cost-effective than smaller units.

(4) Refinery heaters and industrial boilers that require flue gas reheat for optimal SCR performance are costlier than those units not requiring reheat; however, the reheat cost can be offset to a significant extent by reheat recovery.

(5) In general, combinations of controls, primarily low NO_x burners and SCR, are cost competitive with SCR alone between 80 and 90% NO_x removal levels for both heaters and boilers.

(6) On the average, certain combinations of controls are less costly than SCR at NO_x removal levels in the range of approximately 60 to 70%; the cost of the combined system representing approximately 38% of SCR costs at comparable removal levels.

(7) At 50% NO_x removal, SNCR has the lowest removal cost, and at 40%, LNB is least costly; approximately 11% of the cost for 90% removal.

1.6 References

1-1 Leo, P.P., et al., Feasibility and Costs of Applying NO_x Controls on Stationary Emissions Sources in California, Aerospace Report NO. ATR80(7806)-1, The Aerospace Corporation, El Segundo, CA, Contract No. A7-164-30, California Air Resources Board, May 1980.

1-2 Ando, J., NO_x Abatement for Stationary Sources in Japan, EPA-600/7-79-205, U.S. Environmental Protection Agency, Office of Research & Development, Washington, D.C., August 1979.

1-3 Effa, R.C. and Larsson, E.E., Public Meeting to Consider a Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Refineries, Report: SS-81-016, South Coast Air Quality Management District and California Air Resources Board, October 1981.

1-4 Castaldini, C., et al., Technical Assessment of Thermal $DeNO_x$ Process, EPA-600/7-79-117, U.S. Environmental Protection Agency, Office of Research and Development, Washington, D.C., May 1979.

1-5 Personal Communication, Clark, III, J.M., Joy Industrial Equipment Company, 2 October 1981.

2.0 TECHNICAL AND ECONOMIC BASELINE

A discussion of the NO_x control technical considerations and cost premises are presented in this section.

2.1 Technical Considerations

2.1.1 Low NO_x Burners

Staged combustion-type low NO_x burners (LNB) such as the John Zink Company two-stage burner are widely marketed in the U.S. and are extensively utilized in refineries throughout Southern California (Reference 2-1).

A typical LNB operates fuel rich in a primary combustion zone with delayed injection of air in a secondary mixing zone. The result is a decrease in NO_x formed, primarily thermal NO_x, due to increased residence time of gases in the primary combustion zone as well as cooling of the flame by secondary air. Overall NO_x reduction may range from 10% to 50% in gas-fired units; for this study an average of 40% was used (Reference 2-1). In the case of an oil-fired heater or boiler, it is expected that the thermal NO_x portion of total NO_x generated can be reduced on an average by approximately 40% with this type of LNB (Reference 2-2).

Disadvantages associated with the use of low NO_x burners include: 1) longer and larger flame pattern possibly resulting in flame impingement on heat transfer surfaces; 2) burners physically larger in size than conventional burners thereby creating potential retrofit difficulities; 3) other retrofit specific factors such as, furnace geometry and skin temperaure limits; 4) some indications that large numbers of burners may decrease overall NO_x removal performance (Reference 2-1); and 5) necessity to consider each application on case-by-case basis.

2.1.2 Selective Non-Catalytic Reduction

Technical considerations and operating constraints of selective non-catalytic reduction (SNCR) are described in Section 1.3.2. The application of this process has been patented by Exxon Research and Engineering Company.

In commercial applications, NO_x reduction rates of 35 to 70% have been reported (Reference 2-1). In California, 27 units have been outfitted with SNCR; 23 new units and 4 retrofit installations, Reference 2-1.

Major factors affecting the process are: flue gas temperature, and the need for H_2; initial NO_x concentration; NH_3/NO_x mole ratio; residence time at the reaction temperature; and mixing.

For application to boilers, a typical location for NH_3 injection is usually located either within a superheater tube bank or between a superheater tube bank and the steam generator tube bank (Reference 2-1); for heaters, a suitable location appears to be at the transition between the radiant and convective sections; i.e., bridgewall or arch.

Advantages of SNCR include: 1) potential suitability for heaters that cannot be retrofitted with LNB or SCR due to space limitations, or control requirement considerations; 2) use in heaters with large numbers of burners where LNB may not be applicable; 3) a reduced level of duct work and space required in the immediate vicinity of the stationary source.

One disadvantage of SNCR is that it is much less effective for units operating at less than full load. As load is reduced, the ability of SNCR to reduce NO_x decreases if the system is designed for full load (Reference 2-1). Also, there is the possibility of NH_3 carryover due to the inefficient use of ammonia, especially at the lower operating loads. However, it is possible to minimize the effects of varying load on SNCR performance . For example, in order to accommodate temperature changes resulting from changes in load, an array of NH_3 injection grids may be required to maintain control efficiency; i.e., as load is reduced toward 50%, the optimum temperature will likely shift toward the fire box. Use of H_2 can also partially offset this problem at reduced loads with fixed NH_3 injection locations. Another disadvantage of SNCR requires that temperature profiles be determined for each piece of equipment over its operating range.

2.1.3 Selective Catalytic Reduction

This system as described in Section 1.3.3 is designed for reduction of NO_x in a flue gas using ammonia as the reducing agent in the presence of a base metal catalyst.

Ammonia is mixed with air or steam acting as a carrier and subsequently injected upstream of the reactor in the flue gas duct designated as the NH_3/Flue Gas Mixer section. The NH_3/Flue Gas Mixer contains an array of injection nozzles. The flue gas containing the ammonia then flows into a reactor where nitrogen oxides are reduced to nitrogen and water in the presence of a base metal catalyst. A vertical downflow reactor is generally employed where the gas contains particulates.

The catalyst which may be of honeycomb configuration is packed in cases which prevent damage and facilitate shipping and installation. Loading of the catalyst cases can be acccomplished using field equipment.

An ammonia supply system consisting of an ammonia storage tank and supply apparatus including ammonia vaporizer, piping and connection to ammonia equipment is required.

In laboratory and pilot plant testing, catalysts have shown no significant decline in activity after one year of exposure to NO_x laden gas. Further testing of up to two years has shown minimal decline in catalyst activity (Reference 2-3). However, exposure of catalysts to gases loaded with highly abrasive particulates or oily mist should be avoided to prevent masking of the catalyst, reducing its activity. Gaseous fuels should pose no problem in this regard.

An automatic NO_x reactor bypass and isolation system may be included for all installations where excursions might exceed the upper and lower catalyst temperature operating bounds. Combustion signals (such as CO and NO concentrations and pressure drop) or other indications of improper flue gas conditions may also be required to assure that the catalyst is not coated or subjected to damaging chemical or highly abrasive conditions.

Temperature excursions down to 280°C can be tolerated by the catalyst when SO_2 is present only if the operating temperature subsequently rises above 350°C for an equivalent period (Reference 2-3). If sulfur dioxide is not present, the ammonia flow can be curtailed until the temperature again reaches the minimum temperature constraint. Excessively high temperatures will promote excessive oxidation of sulfur and sintering of the catalyst material (Reference 2-3). At least 1% excess O_2 is required for desired catalyst performance (Reference 2-3).

Operating experience for SCR units is quite extensive. Over 100 commercial sized units in Japan (Reference 2-2 and 2-4) and at least 3 in the United States (Reference 2-2) have been installed. The three systems in the U.S. have recently been reported in a joint report of the California Air Resources Board and the South Coast Air Quality Management District (Reference 2-1). In one case, two new gas-fired 50 MMBtu/hr Zurn steam boilers have been outfitted at Fletcher Oil and Refinery Company with a UOP SCR system designed to perform at a 50% NO_x removal level; however, the system has been designed to accommodate catalyst and flue gas flow for 90% reduction. Refinery personnel reported to CARB staff that there have been no major problems with the control system (Reference 2-1). Another SCR system designed to operate at 90% NO_x removal has been retrofit to a gas-fired 65 MMBtu/hr natural draft process heater at USA Petrochem refinery. No problems have been reported with the SCR system (Reference 2-5). Southern California Edison is retrofitting an SCR system on a 107.5 MW slip stream (approximately 1/2 of total flue gas flow) of its Huntington Beach Unit #2 oil-fired steam boiler. It has been designed for 90% control of NO_x emissions with ammonia slip less than 10 ppm.

Table 2-1 summarizes the characteristics directly influencing SCR reactor and catalyst bed sizing for the heaters and boilers described in Section 3.0. The emissions of each unit, the amount of reheat required, catalyst volume, space velocity (on a wet and dry basis), catalyst dimensions, superficial gas velocity, and calculated pressure drop through the catalyst bed are shown. For completeness, space velocity is presented on both a wet and dry basis in Table 2-1. Throughout the report, references and discussions related to space velocity are on a dry basis. In sizing the

TABLE 2-1

CATALYST BED SIZING CHARACTERISTICS

EQUIP.	EQUIP. DESIG.	UNIT SIZE (MMBTU/HR)	FUEL[b]	FLUE GAS FLOW WET BASIS (SCFM)	FLUE GAS FLOW DRY BASIS (SCFM)	EMISSIONS NO_x[c] (PPM,DRY)	EMISSIONS SO_2 (PPM,DRY)	EMISSIONS PARTICULATES[f]	EMISSIONS TEMP (°C)	REHEATED TO °C	CATALYST VOLUME, FT^3	SPACE VELOCITY WET BASIS (HR^{-1})	SPACE VELOCITY DRY BASIS (HR^{-1})	APPROX. CATALYST SIZE; FT^2, FT AREA	APPROX. CATALYST SIZE; FT^2, FT LENGTH	SUPERFICIAL GAS VELOCITY[e], M/SEC	CALCULATED CAT. BED Δp, mmH_2O
Refinery Heater	A	65	R	15,300	13,200	85	Nil	Nil	410	N/A[g]	128	7200	6200	25.0	5.1	2.8	125
	B	93	R	20,000	17,200	90	Nil	Nil	160	260	233	5200	4400	42.5	5.5	2.1	70
	C	115	R	24,100	20,600	73	Nil	Nil	388	N/A	287	5100	4300	42.2	6.8	2.5	140
	D	164	R	32,300	27,600	182	Nil	Nil	238	260	438	4400	3800	64.0	6.8	2.2	110
	E	435	R	95,100	81,400	151	Nil	Nil	260	N/A	1550	3100	3800	182	8.5	2.3	150
Refinery Heater	F	4	N	805	670	75	Nil	Nil	132	260	9	5200	4300	4.0	2.3	0.9	10
	H	22[d]	O	4,230	3,750	367	194	0.33	182	260	90	3000	2300	10.6	8.5	1.8	90
	I	150	O	30,600	24,800	103	7	0.04	232	300	598	3100	2500	64.0	9.3	2.0	135
	J	336	N	70,900	60,500	152	Nil	Nil	177	260	1125	3200	3900	160	7.0	1.9	105
CO Boiler	K	582	R	350,300	331,300	158	72	0.01	255	N/A	8045	2600	2500	840	9.6	2.0	110

a 90% removal at full load
b R=Refinery gas, N=Natural gas, O=NO.2 Fuel Oil
c ppm dry, at 3% O_2
d designed for use with oil, study case G for this unit considers use of natural gas though the unit.
e dry basis grains std/cu.ft.
g not applicable

catalyst beds and reactors, generic criteria outlined in Reference 3-3 were used and no attempt was made to optimize or tailor space velocity, pressure drop and fan size, or reheat temperature from a engineering cost perspective for each unit.

Criteria used for catalyst bed sizing are summarized in Table 2-2 and includes type of fuel, flue gas temperature, SO_2 emissions, and particulate loading. In general, for a gas-fired unit under conditions of optimum flue gas temperature and negligible SO_2 and particulate emissions, a nomimal space velocity of approximately 6000 hr^{-1} (dry basis) could be considered. For cases in which suboptimum temperatures are encountered either independently or in combination with SO_2 and particulate loading, a lower space velocity would be required as shown in Table 2-2. Oil-firing necessitates a lower space velocity due to associated SO_2 emissions and particulate loading. Flue gas temperatures for optimum catalyst performance were considered to be in the range of 350 to 400°C and the low operating temperatures are those between 255 and 260°C. As was noted above, tradeoffs between the cost of increasing the reheat temperature and the associated equipment and fuel costs versus the corresponding reduction in catalyst volume (increased space velocity) were not conducted.

Figure 2-1 shows the linear relation between catalyst volume and flue gas volumetric flow on both a wet and dry basis. Corresponding space velocities are also indicated.

2.1.4 Combination of Controls

Results of studies and recent operating experience as described and referenced in Sections 2.1.2 and 2.1.3 have shown the feasibility of using SCR for removing 90% NO_x emissions from refinery heaters or industrial boilers. In many instances its use tended to be expensive relative to LNB and SNCR, although more effective. Because of the relatively low cost of LNB and SNCR compared to SCR, this study was conducted to determine the potential for achieving levels of control between 50% to 90% NO_x removal at a cost less than for an equivalent level of SCR control.

The application of a combination of controls in this report considers the cummulative effect of the three basic control technologies;i.e., LNB, SNCR, and SCR. On the basis of visits to refineries and other installations, it has been determined that existing space and physical configuration of the stationary sources can accommodate the control system in question. However, this does not imply that no installation problems exist. Therefore a retrofit factor was applied to total capital investment to account for retrofitting.

The following combinations with their respective expected NO_x reduction levels were examined: LNB (40%) + SNCR (50%); LNB (40%) + SCR (50, 60, 70, 80, 90%); SNCR (50%) + SCR (50, 60, 70, 80, 90%); and LNB (40%) + SNCR (50%) + SCR (50, 60, 70, 80, 90%). The cummulative NO_x removal rates for any combination of control removal rates can be found using the nomograph in Figure 2-2.

TABLE 2-2

CATALYST BED SIZING CRITERIA AS RELATED TO REFINERY HEATER AND INDUSTRIAL BOILER EMISSION CHARACTERISTICS

FUEL	FLUE GAS CONDITIONS			SPACE VELOCITY,[d] NOMINAL (HR^{-1})	APPLICABLE EQUIPMENT, DESIGNATION[e]
	TEMP[a]	SO_2 [b]	PARTICULATES[c]		
GAS	OPTIMUM	NONE	NONE	6200	A
GAS	LOW[f]	NONE	NONE	4200	B, C, D, E, F, J
OIL	LOW	SOME	SOME	2400	H, I
GAS	LOW	SOME	SOME	2500	K

[a]OPTIMUM = 350 - 400°C
LOW = 255 - 260°C

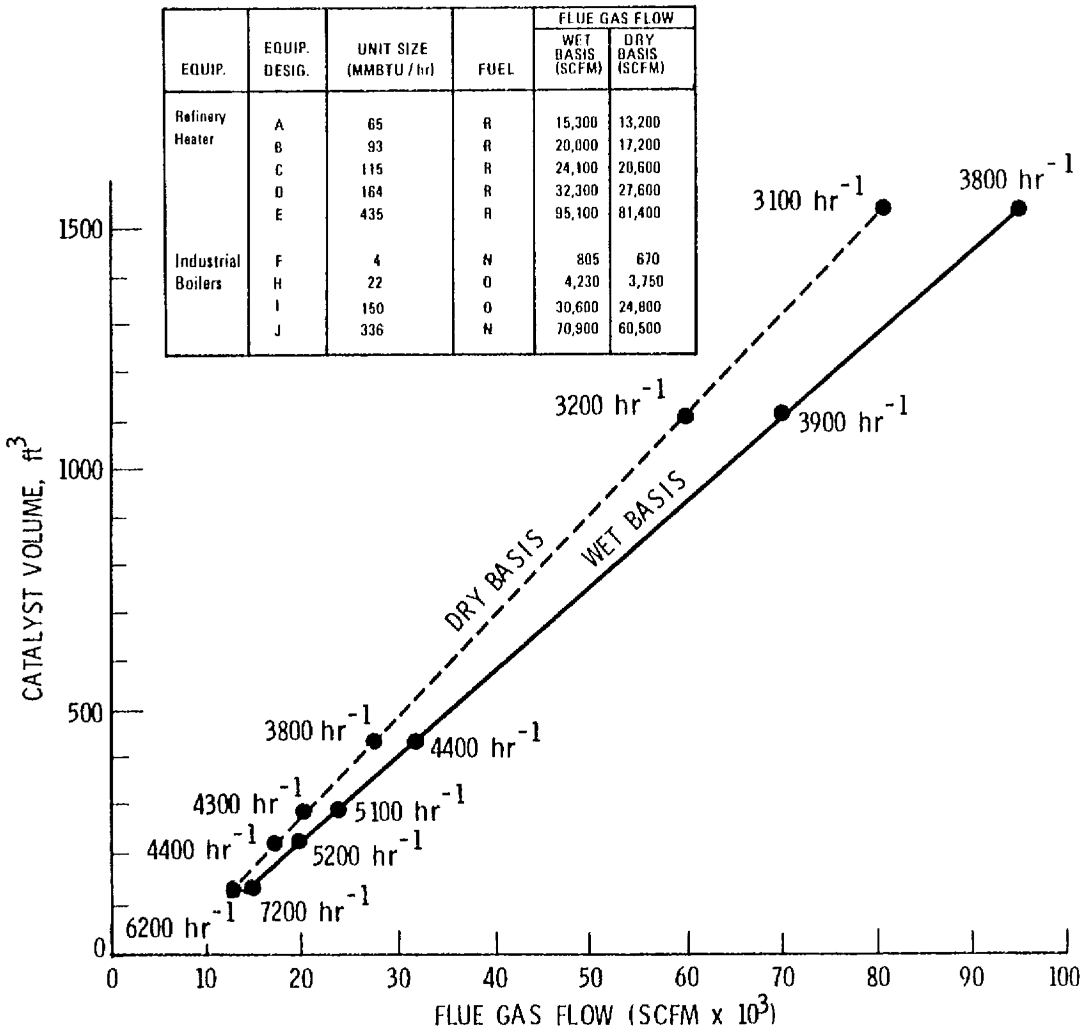
[b]SOME = 5 - 200 ppm

[c]SOME = 0.01 - 0.3 GRAINS/STANDARD CUBIC FEET

[d]BIANNUAL CATALYST REPLACEMENT. SPACE VELOCITY IS ON A DRY BASIS

[e]DESIGNATION - THIS REPORT

[f]TEMPERATURE BASED ON MINIMIZING REHEATER AND HEAT RECOVERY EQUIPMENT AND FUEL REQUIREMENTS



EQUIP.	EQUIP. DESIG.	UNIT SIZE (MMBTU / hr)	FUEL	FLUE GAS FLOW WET BASIS (SCFM)	FLUE GAS FLOW DRY BASIS (SCFM)
Refinery Heater	A	65	R	15,300	13,200
	B	93	R	20,000	17,200
	C	115	R	24,100	20,600
	D	164	R	32,300	27,600
	E	435	R	95,100	81,400
Industrial Boilers	F	4	N	805	670
	H	22	O	4,230	3,750
	I	150	O	30,600	24,800
	J	336	N	70,900	60,500

Figure 2-1 Catalyst Volume vs. Flue Gas Flow (Wet & Dry Basis)

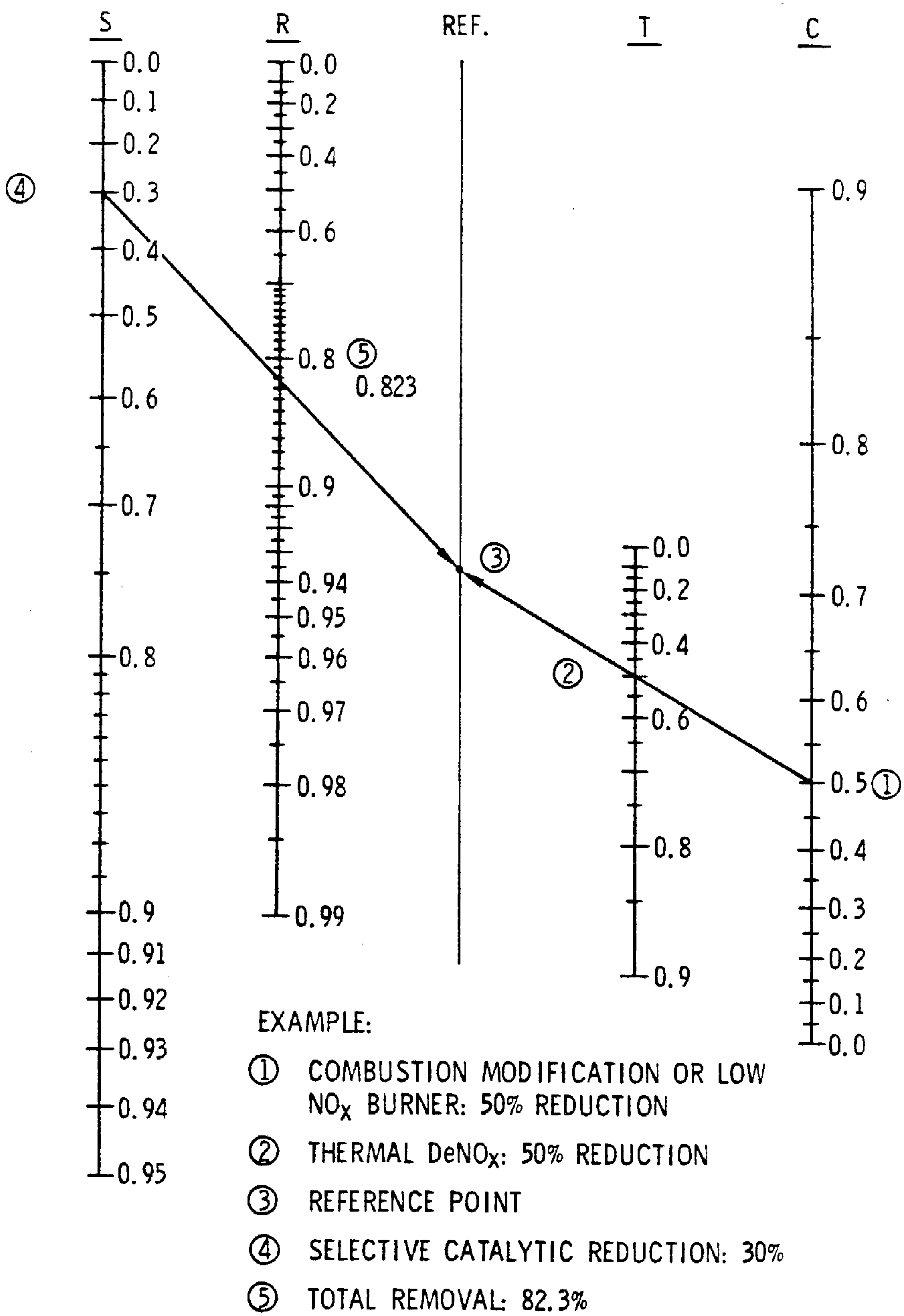


Figure 2-2 Nomograph to Determine Cumulative NO_x Control Rates

Control systems involving SCR removal rates less than 90% were based on a scaled-down SCR reactor. In it, a slip stream portion of the total exhaust gas volume is treated. However, the reactor operates at a full 90% removal rate. The remaining untreated portion of the exhaust gas is remixed with the treated portion downstream of the reactor. The overall removal rate is then based on the amount of gas that bypasses the reactor. Thus, the total equivalent removal rate is a selected value less than 90% (see Figure 2-3).

Other advantages of utilizing a combination of controls in addition to those already described are: 1) some degree of system redundancy is provided; 2) that in some cases, high levels of control can be attained in a stepwise manner; 3) the combination of SNCR followed by SCR may be effective as a means of reducing ammonia carryover; and 4) since low NO_x burners operate at reduced excess air in comparison with conventional burners, there is the possibility of improving unit energy utilization efficiency with the use of LNB in conjunction with, or without, the use of SNCR or SCR.

One significant disadvantage of a combination approach is that the complexity of the overall control system is substantially increased. Also, certain combinations are costly (see Section 1.4).

2.2 Economic Premises

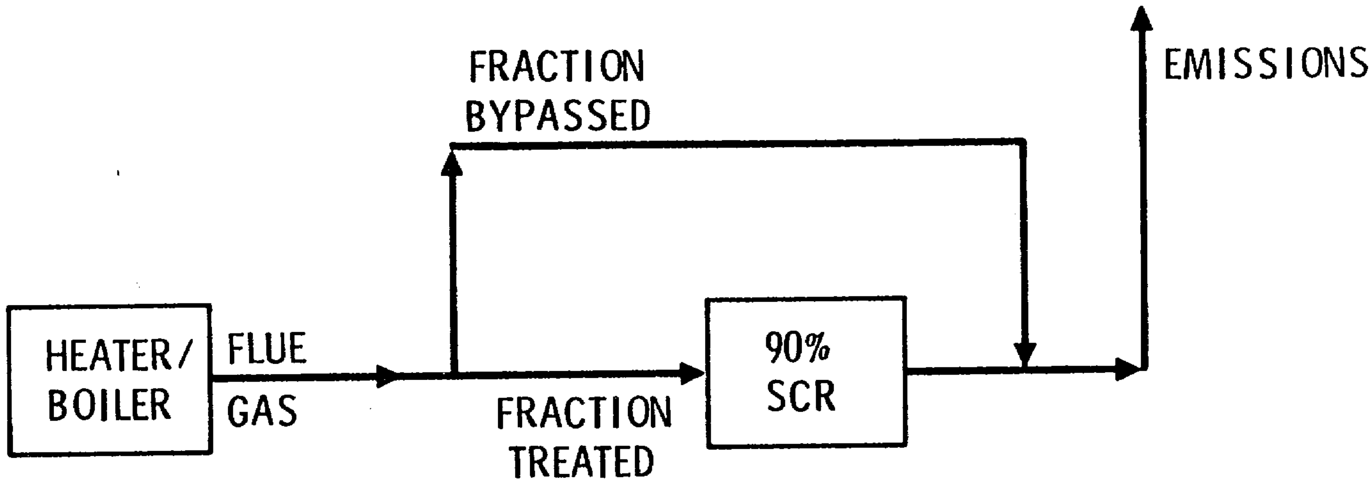
The basis which was used to estimate control system capital requirements, operating costs, and annualized costs are included in the premises discussed below. All estimates are expressed in mid-1981 dollars.

2.2.1 Capital Requirements

Capital requirements includes total plant investment cost and investment charges including preproduction costs, allowance for funds during construction, and retrofit costs (Reference 2-2 and 2-6). Table 2-3 outlines these costs and indicates appropriate references on which they were based.

Equipment/Facilities includes all costs for material and labor to install the complete system. Structures costs, site preparation, storage, landscaping, major process equipment, auxilliary equipment (piping, instrumentation, electrical), and indirect costs such as construction expense and contractor fee are also included. These costs vary for each control system, depending on unit size and configuration. The tables in Appendices A, B, and C outline or summarize equipment costs for each unit and type of individual control technology. Burner cost estimates as a function of size for two pressure drop conditions across the burner are presented in Figure 2-4.

Engineering/Contingency is estimated at 25% of process equipment capital and includes design charges and fees (Reference 2-6).



DESIRED NO_x REDUCTION, %	FLUE GAS FRACTION BYPASSED, %	FLUE GAS FRACTION TREATED, %
90	0	100
80	11	89
70	22	78
60	33	67
50	44	56

Figure 2-3 SCR Bypass Configuration to Achieve Control Levels Below 90%

Table 2-3. CAPITAL REQUIREMENTS[a]

CAPITAL INVESTMENT COST	AMOUNT	REFERENCE
CAPITAL FACILITIES COST		
EQUIPMENT/FACILITIES	(SEE TABLES IN APPENDICES A, B, AND C)	2-16 THROUGH 2-28
ENGINEERING/CONTINGENCY	25% EQUIPMENT/FACILITIES	2-6, 2-2
MISCELLANEOUS COST		
RETROFIT	15% OF CAPITAL FACILITIES	2-6, 2-2
PREPRODUCTION	2% OF CAPITAL FACILITIES (INCLUDING RETROFIT) + 1 MO. OPERATING COST	2-6
ALLOWANCE FOR FUNDS DURING CONSTRUCTION	15% OF ABOVE COST FOR ONE MONTH	2-2

[a]APPLIES TO SNCR AND SCR; LNB ESTIMATES PREPARED AS IN REFERENCE 2-2

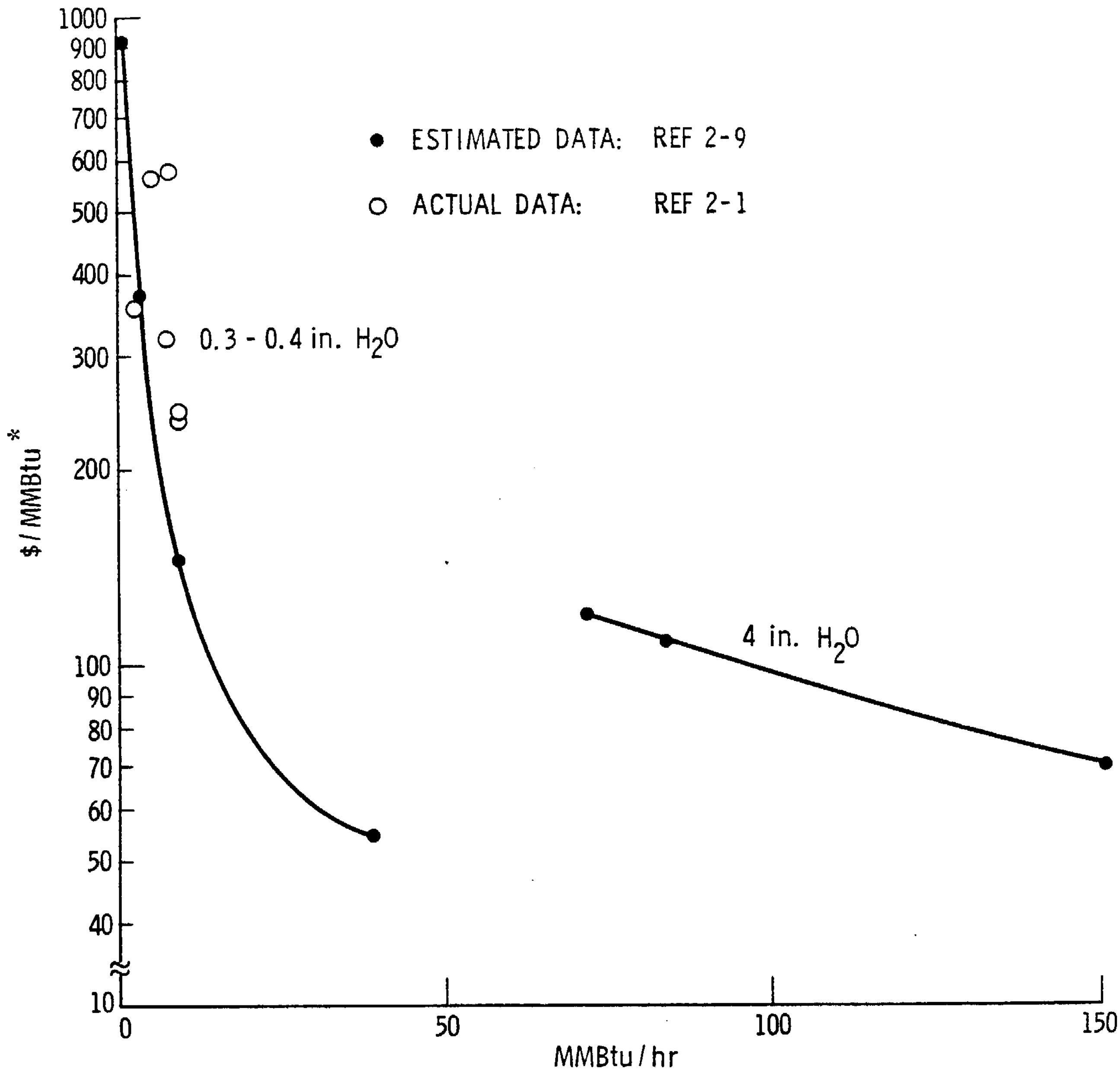


Figure 2-4 Basic Burner Cost as a Function of Unit Size

*Note: log scale

Retrofit is basically a factor due to uncertainty in installation and equipment requirements (exclusive of major identifiable items such as draft fans and motors). This charge is highly deplendent on the availability of real estate near the emission source to physically accommodate major equipment or structures. It is estimated as 15% of process equipment capital costs plus engineering costs (Reference 2-2 & 2-6). This percentage applies primarily to SCR and SNCR. A factor of 72% was used for LNBs based on an average of actual installation/retrofit costs derived from Reference 2-1.

Preproduction costs include operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of materials during startup. These costs are estimated at one months fixed operating costs plus 2% of capital investment to cover expected changes and modifications to process equipment (Reference 2-6).

Allowance for Funds During Construction is estimated by assuming a 15% per year rate applied to all the above capital costs taken for one month which is the stationary source estimated down time (Reference 2-2).

2.2.2 Annual Operating Costs

Operating costs are primarily based on unit operating load and total number of hours per year in service. Annual operating costs were separated into variable and fixed costs, Table 2-4. Fixed costs included operating labor, maintnance and overhead. Variable costs included consumable and replacement items such as ammonia and catalyst, respectively.

2.2.3 Annualized Cost

Annualized costs for each alternative were determined by applying an annualization factor to the total capital investment cost and then combining the result with the operation and maintenance (O&M) costs. The factor utilized is 0.2736 (Reference 2-1) and is based on an installation lifetime of 13 years.

The costs do not reflect any tax savings that a company may incur from the installation of pollution control equipment such as investment tax credits, deduction for interest expense or depreciation. All of these factors would tend to reduce the net cost of the equipment to the company. Also the opportunity costs such as those resulting from lost production during retrofit shutdown were not in included. This was considered to be a reasonable approach because the control equipment buildup was assumed to be incurring in parallel with normal equipment operation and installed or connected during normal maintenance shutdown periods. However, if operational schedules do not permit such an approach, lost production should be considered.

Table 2-4. OPERATING COSTS

COST FACTORS	AMOUNT	REFERENCE
FIXED COSTS		
OPERATING LABOR	$\frac{\$20}{HR} \times \frac{\text{NO. HRS. IN SERVICE}}{YR} \times$ $5\,(10^{-3})\,\frac{MEN}{MWe} \times$ UNIT SIZE IN MWe	2-2, 2-6
MAINTENANCE (Materials & Labor)	3% PROCESS CAPITAL	2-6, 2-2
OVERHEAD	1% LABOR	2-6
VARIABLE COSTS		
NH_3	\$0.12/lb	2-1
CATALYST**	\$582/FT^3	2-3
FUEL	\$9.65/MMBTU (OIL) \$3.88/MMBTU (GAS)	2-16 2-16
STEAM	\$3.50/1000 LB	2-1
ELECTRICAL POWER	\$0.069/kWh	2-16
H_2	\$1.10/lb	2-1

**CHANGED EVERY 2 YEARS OVER 13 YEAR LIFE IN SCR UNITS (EXCEPT FOR GLASS FURNACE, WHICH IS REPLACED EVERY YEAR)

2.3 References

2-1 Effa, R.C. and Larsson, E.E., Public Meeting to Consider a Suggested Control Measure for the Control of Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Refineries, Report SS-81-016, South Coast Air Quality Management District and California Air Resources Board, October 1981.

2-2 Leo, P.P., et al., Feasibility and Cost of Applying NO_x Controls on Stationary Emission Sources in California, Contract No. A7-164-30, California Air Resources Board, May 1980.

2-3 Clark, III, J. M., Joy Manufacturing Company, Personal Communication, 2 October 1981.

2-4 Ando, J., "SO_2 and NO_x Abatement for Coal-Fired Boilers in Japan", Symposium on Flue Gas Desulfurization, Houston, TX, October 1980.

2-5 Blair, J.B., et al., "Refinery Catalytically Cuts NO_x Emissions", Oil & Gas Journal, 12 January 1981.

2-6 Maxwell, J.D., et al., Preliminary Economic Analysis of NO_x Flue Gas Treatment Processes Using TVA and EPRI Economic Premises, Contract No. RP 783-3, Electric Power Research Institute, Palo Alto, January 1981, pg. 28-35.

2-7 Guthrie, K.M., Process Plant Estimating and Control, Craftsman, 1974.

2-8 Galgano, M.A., Economic Case Study, Dry Catalytic DeNO_x System, Hitachi-Zosen, E-07148-G, July 1978.

2-9 Bell, R., Personal correspo ndence, John Zink Company, 17 September 1981.

2-10 Ando, J., NO_x Abatement for Stationary Sources in Japan, U.S. Environmental Protection Agency, Office of Research and Development, Washington, D.C., EPA-600/7-79-205, August 1979.

2-11 Vanator, W.M. and Neveril, R.B., "Estimating the Size and Cost of Ductwork", Chemical Engineering, McGraw-Hill, V. 87, No. 26, 29 December 1980.

2-12 Page, J.S., Estimator's Manual of Equipment and Installation Costs, Gulf Publishing, Houston, 1963.

2-13 Woods, D.R., Financial Decision Making in the Process Industry, Prentice-Hall, 1975, pg. 301.

2-14 Choi, P.S.K., et al., Flue Gas Reheat for Wet F&D Systems, Battelle Memorial Laboratory, EPRI FP-361, February 1977.

2-15 Enslin, P., Personal Communication, Vaporhase, 19 August 1980.

2-16 Energy User News, V. 6, No. 28, 13 July 1981.

3.0 ASSESSMENT OF COMBINED NO_x CONTROL STRATEGIES

3.1 Refinery Heaters

3.1.1 65 MMBtu/Hr Catalytic Reformer Heater

3.1.1.1 Characteristics

Off-gases from various refinery processes are collected and mixed in a common storage system and supplied to various heaters as required. As a result, the composition of the gases may change during steady operation of a given heater. A typical gaseous fuel composition is shown in Table 3-1. To assure the availability of excess air despite variations in a fuel composition, the fuel is burned with more than normal excess air (about 20% excess air or about 4% O_2 in the flue gas). Figure 3-1 illustrates the fuel and air flow rates to the unit.

The fuel is burned in 24 natural draft gas burners, which are arranged linearly along the floor near a refractory wall. Burner capacity is approximately 2.9×10^6 Btu/hr* (73×10^4 kcal/hr). The heaters utilize combustion air at ambient temperature. Tubes carrying process fluid are located on the opposite wall in the radiant section and in the convective section along the roof.

Part of the combustion air is premixed with the fuel, with the rest entering close to the burner as secondary air. Both fuel and combustion air are introduced at ambient temperature. The combustion gases are directed against and along the refractory wall.

The wall is heated (glowing in some spots) and provides radiant heating of the tubes carrying the gasoline mixture. The gases, which have cooled considerably, then pass through a bundle of tubes located in the roof of the heater and through a steam generating coil in a final convective pass, before entering the stack. Temperature at the stack is about 770°F (410°C). The combustion system is relatively simple, and the heat transfer arrangement assures relatively uniform heating of the process fluid despite any localized hot spots which might exist in the gases or on the refractory wall.

Furnace operation is essentially continuous at approximately 60 MM Btu/hr heat input with scheduled shutdowns approximately every 4 to 6 months (for 2 weeks) for catalyst regeneration and minor repairs, and every tow years for about a month during catalyst dumping, screening, reloading, and major maintenance. The furnaces are about 20 years old with an unknown life expectancy. No specific air pollution controls are used on these units at this time other than operation at minimum excess air consistent with the uncertainty in fuel composition discussed above.

---

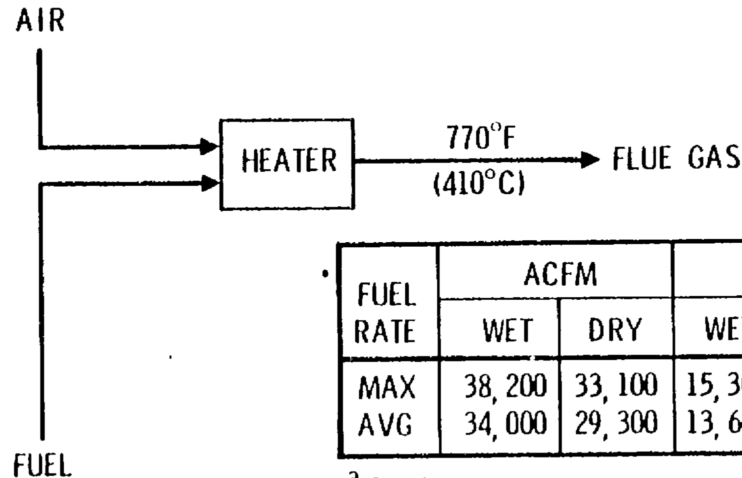
*70×10^6 Btu/hr x 1/24 burners = 2.9×10^6 Btu/hr-burner.

TABLE 3-1. TYPICAL REFINERY HEATER GASEOUS FUEL*
FOR 15 MMBTU/HR HEATER

CONSTITUENT	VOLUME %
H_2	12.6
N_2	0.2
CO	0.6
CH_4	32.8
C_2	17.7
C_3	27.2
C_4	7.5
C_5	1.4
	100.0
Btu/SCF	1476

*Source: Leo, P.P. et at. Feasibility and Costs of Applying NO_x Controls on Stationary Emission Sources in California, Contract No. A7-164-30, California Air Resources Board, May 1980.

FUEL RATE	AIR, SCFM	EXCESS O_2, %
MAX	14,300	5.0
AVG	12,300	3.8



FUEL RATE	ACFM		SCFM		NO_x	
	WET	DRY	WET	DRY	ppm[a]	lb/hr[b]
MAX	38,200	33,100	15,300	13,200	85	7.9
AVG	34,000	29,300	13,600	11,700	77	6.7

[a] 3% O_2, dry
[b] As NO_2

FUEL RATE	FUEL, SCFM	HEAT INPUT, MMBtu/hr
MAX	1,050	65
AVG	950	58

HEATER: HORIZONTAL BOX TYPE.
JOHN ZINK UCV-4
24 NATURAL DRAFT GAS BURNERS
(2.9×10^6 Btu/hr capacity per burner)

Figure 3-1 65 MMBtu/Hr Catalytic Reformer Heater

Figure 3-1 65 MMBtu/Hr Catalytic Reformer Heater

Current NO_x emissions, as reported, at approximately 89% load are 70 to 85 ppm (adjusted to 3% O_2). Oxygen concentration in the flue gas averages 3.8% and is 5.0% maximum. The quantity of NO_x emitted is summarized in Figure 3-1. NO_x emissions rates (expressed as NO_2) are 6.7 to 7.9 lb/hr for heat input of 58 and 65 MMBtu/hr.

3.1.1.2 Cost Estimates

Figure 3-2 summarizes the cost-effectiveness of alternative NO_x removal systems for the gas-fired 65 MMBtu/hr catalytic reformer operating at 89% load. At a 90% NO_x removal rate, SCR alone at $4.04/lb NO_x removed is the least costly of any combination of controls. However, at 70% overall NO_x removal, the combination of LNB plus SNCR, operating at 40% and 50% NO_x removal rates, respectively, becomes relatively less costly than SCR alone; i.e., $3.46/lb NO_x versus $4.40/lb NO_x removed).

As the size and relative NO_x removal rates of an SCR system decrease, cost-effectiveness can be expected to be less advantageous. This occurs because as the amount of NO_x that must be removed decreases equipment costs tend to remain a constant, or decrease, at a slower rate than the decrease in NO_x removed.

Total capital investment for all 24 LNBs is expected to be about $145,800 ($900/MMBtu per hour) (see Table A-5, Appendix A). This translates into an annual cost of approximately $46,500 or $2.20/lb NO_x removed for an estimated 40% reduction in NO_x emissions.

Total annual cost for an SNCR system designed for 50% NO_x removal efficiency sized for this unit operating at 100% load is estimated at $81,500 (See Table A-6, Appendix A). Operating and maintenance (O&M) charges are approximately 29% of the total annual cost with the remainder being annual charges on capital. Total capital investment for SNCR was estimated to be $210,700.

Total capital investment for an SCR system designed for 90% NO_x removal at 100% load is estimated at $480,500. This is based on a 15% retrofit factor ($11,500) as previously defined (i.e., a retrofit contingency covering installation complexities; see Section 2.2.1). If the retrofit factor is taken to include retrofit-peculiar equipment and other capital expenses; i.e., ducting, expansion joints, elbows, fan and additional engineering/contingency changes, it becomes $110,500 or 23% of new installation cost (see Table A-1, Appendix A). Operating and maintenance charges for the unit operating at approximately 89% load are estimated at $60,700 which amounts to 32% of the total annual cost ($192,200). Capital charges account for the remaining $131,500.

3.1.2 93 MM Btu/Hr Refinery Heater

3.1.2.1 Characteristics

The 93 MMBTU/HR heater in this study is a

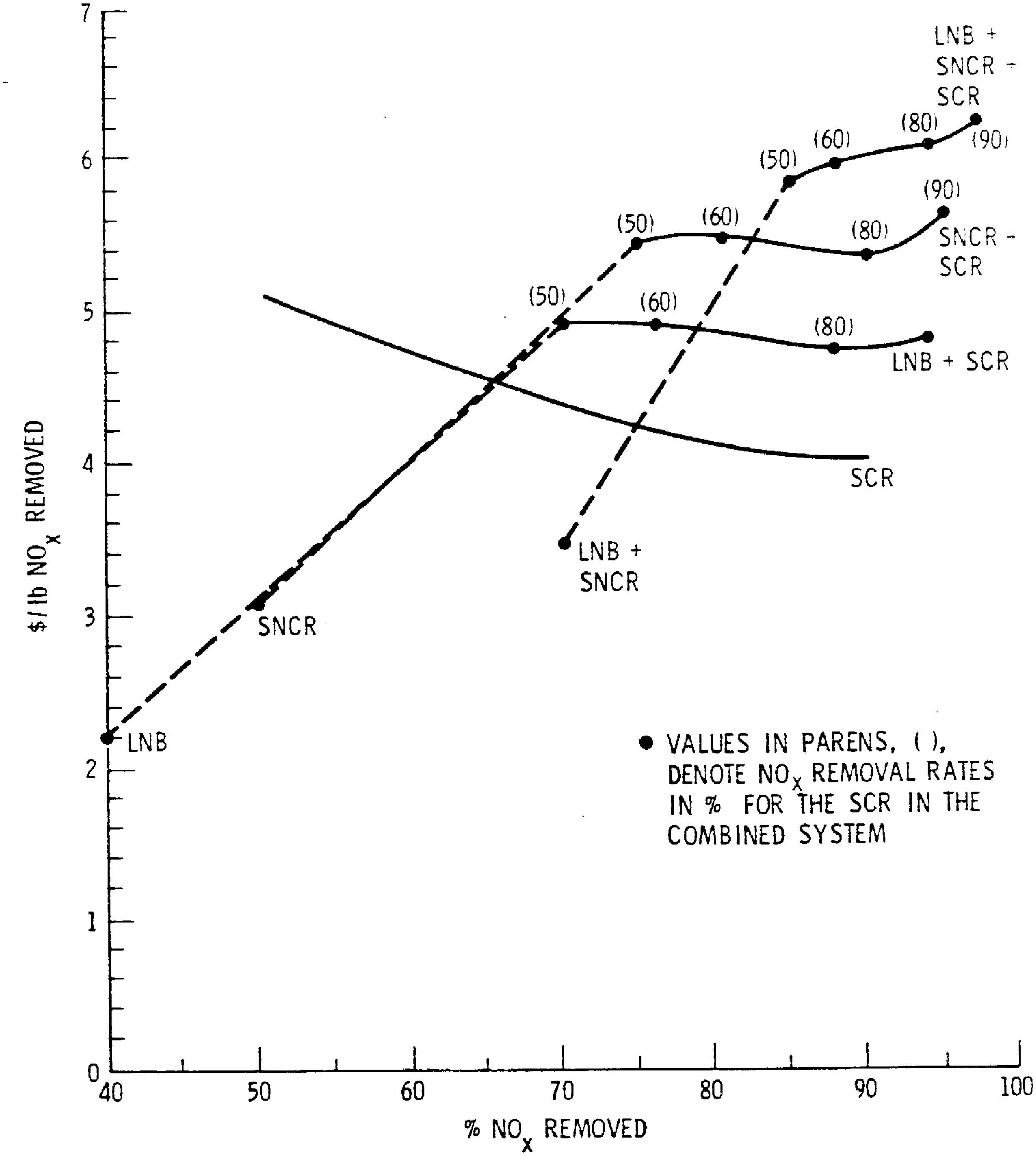


Figure 3-2 Cost of Alternative NO_x Removal Systems for a Gas-Fired 65 MMBtu/Hr Catalytic Reformer Heater - 89% Load (1981 Dollars)

box-type unit manufactured by U.S. Petrochem. Seventy-two horizontally fired natural draft burners, John Zink Model FFC-20, are arranged in four rows along the sides of the heater. Above the firebox and process tubes is a convective section containing steam and boiler feed water (BFW).

Figure 3-3 is a representation of the heater as was currently being operated; i.e., 67.2 MM Btu/hr(approximately 72% of maximum load). Fuel, air, and exhaust gas flows as well as expected emissions are also shown. These conditions may vary depending on the composition of refinery gas which changes as a function of its availability from other processes. A typical fuel analysis is given in Table 3-2 and serves as the basis for this analysis.

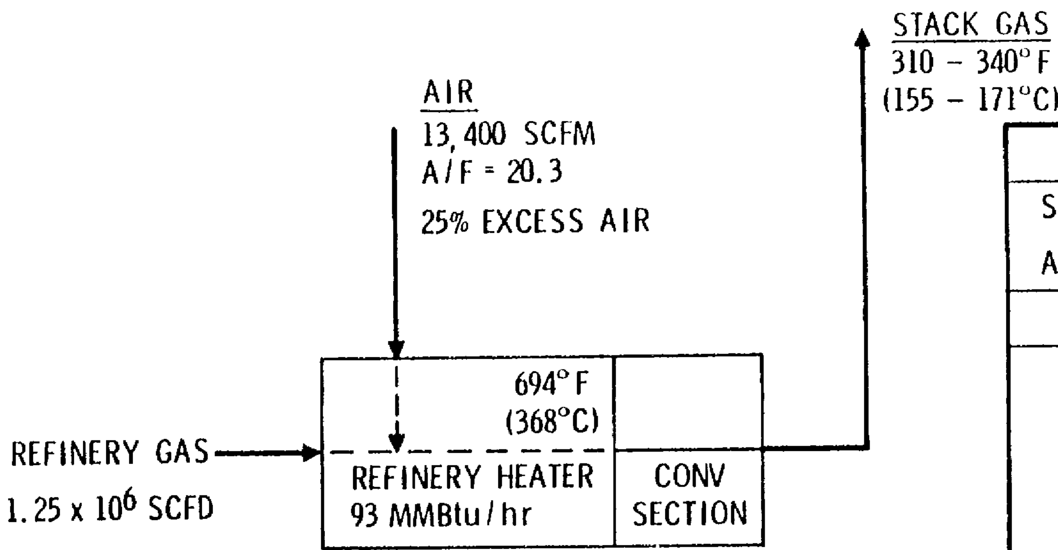
Refinery gas at the rate of 868 SCFM with an average heating value of 1290 Btu/SCF is fired at an air/fuel ratio of 20.3 (25% excess air). The gas temperature leaving the combustion section of the heater is approximately 694°F (368°C). The process tubes are located in this region of the unit. The combustion gas then enters the convection section where heat is tranferred to a series of steam and BFW tubes. Finally, the exhaust gases at approximately 310-340°F (155-171°C) are discharged to the atmosphere through the stack at a rate of 12,400 SCFM, dry (20,100 ACFM, dry). Flue gas composition is also presented in Figure 3-3.

SO_2 and particulate emissions are negligible; however, NO_x (reported as NO_2) is discharged at a rate of approximately 8.6 lb/hr or 90 ppm* corrected to 3% O_2, dry. This translates to a NO_x emission factor equivalent to 0.13 lb/MM Btu based on normal operation at 72% of maximum load.

3.1.2.2 Cost Estimates

Cost estimates of NO_x control equipment for this heater were computed on the basis of 3 SCR conditions: 1) operation at 100% load without reheat and reheat recovery; 2) operation at 100% load with 89°C reheat but no reheat recovery; and 3) operation at 72% load with 89°C reheat and with a reheat recovery system achieving 65% thermal efficiency. The 89°C represents the increase in exhaust gas temperature for normal operation of the catalyst. Figures 3-4, 3-5, and 3-6 illustrate cost-effectiveness vs. NO_x removal rates for the combination control strategies associated with each of the three cases described. Additionally, Table 3-3 is a summary of data represented in the figures for SCR alone.

*This number was supplied by the equipment operator for 100% load and verified on the basis of emission factors obtained from ARB/joint government study and ARB/KVB study reported in CARB Report No. C-9-035/036/037/038/039, Evaluation Test to Determine NO_x Emission Factors from Refinery Combustion Sources, and AP-42.



868 SCFM
1290 Btu/SCF } 67.2 MMBtu/hr
OPERATING AT APPROXIMATELY
72% OF MAXIMUM LOAD

HYDROTREATING
REACTOR FEED
HEATER: PETROCHEM HORIZONTAL
BOX TYPE, NATURAL DRAFT
72 ZINK FFC-20 BURNERS

	WET	DRY
SCFM	14,400	12,400
ACFM	23,500	20,100
	% WET	% DRY
N_2	73.3	85.6
CO_2	8.6	10.0
O_2	3.7	4.4
H_2O	14.3	0.0

lb/hr[b]	lb/10^6 Btu[b]		PPM, DRY
-	-	SO_2	NIL
8.6	0.13	NO_x	90 [a]
-	-	PARTICULATES	N/A

[a] Based on 90 ppm at max fire duty (3% O_2 dry)
[b] 72% load, 3% O_2, dry as NO_2

Figure 3-3 Operating Characteristics of a Gas-Fired 93 MMBtu/Hr Hydrotreating Reactor Feed Reacter Feed Heater

TABLE 3-2: REFINERY GAS COMPOSITION*
FOR 93 MMBTU/HR HEATER

CONSTITUENT	VOLUME %
H_2	26.5
CH_4	35
C_2H_6	13.3
C_2H_4	0.9
C_3H_8	12
C_3H_6	2.6
n C_4H_{10}	5.3
i C_4H_{10}	2.6
n C_5H_{12}	0.4
i C_5H_{12}	0.4
N_2	0.5

*Source: Major Southern California Refinery

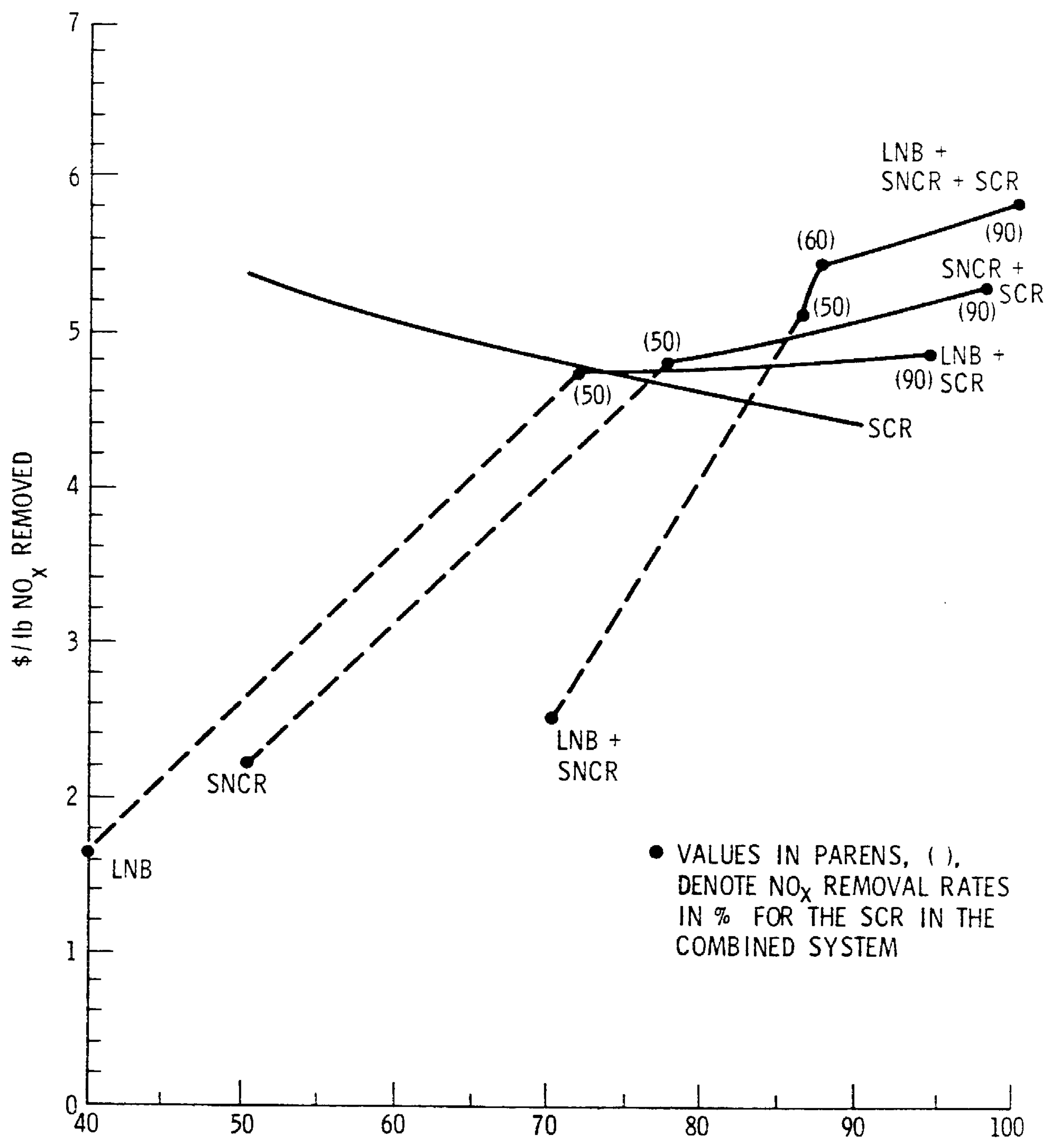


Figure 3-4 Costs of Alternative NO_x Removal Systems for a Gas-Fired 93 MMBtu/Hr Refinery Hydrotreating Heater - 100% Load with Reheat of 89°C (1981 Dollars)

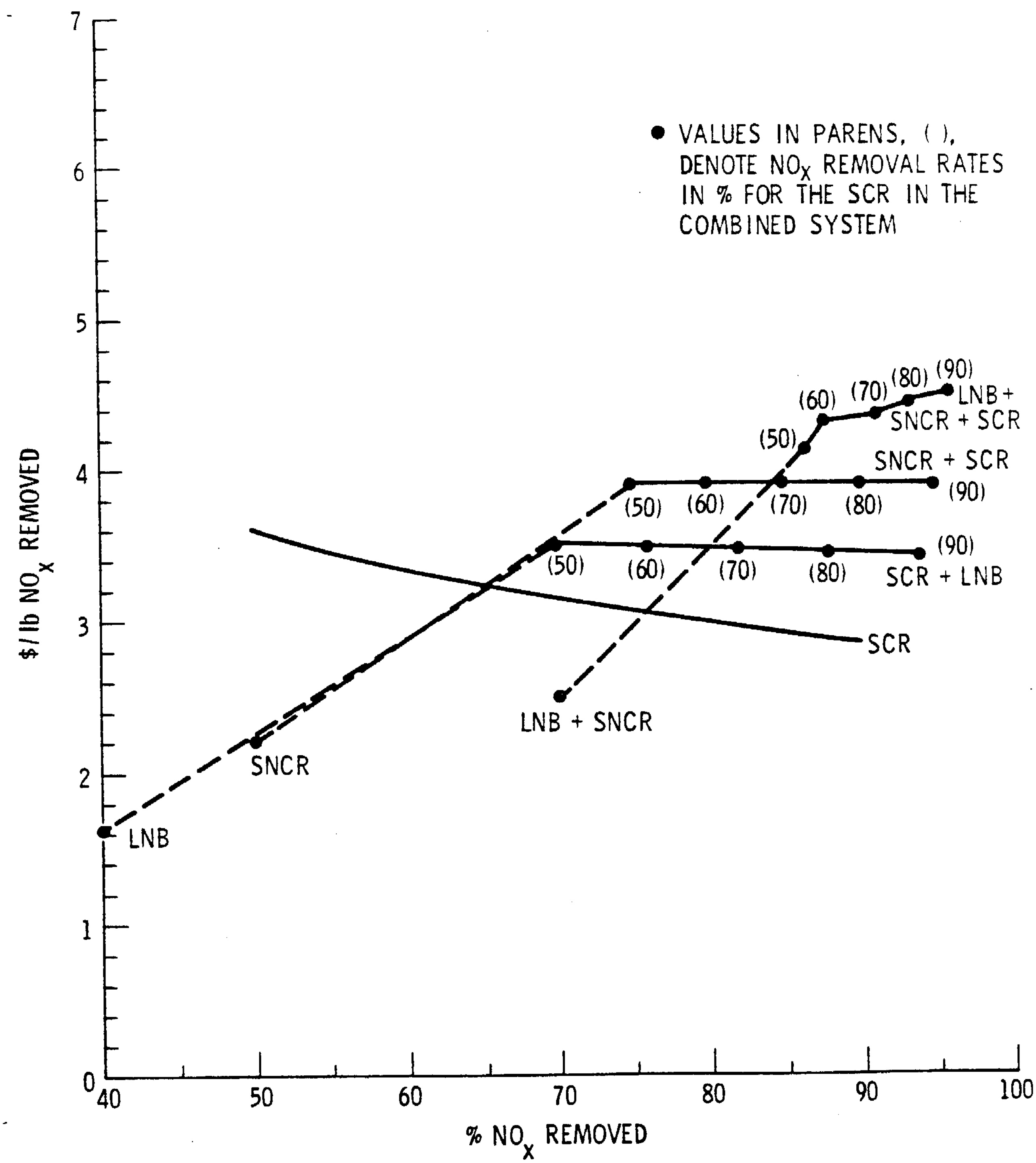


Figure 3-5 Costs of Alternative NO_x Removal Systems for a Gas-Fired 93 MMBtu/Hr Refinery Hydrotreating Heater - 100% Load and Reheat Not Included: Baseline Case (1981 Dollars)

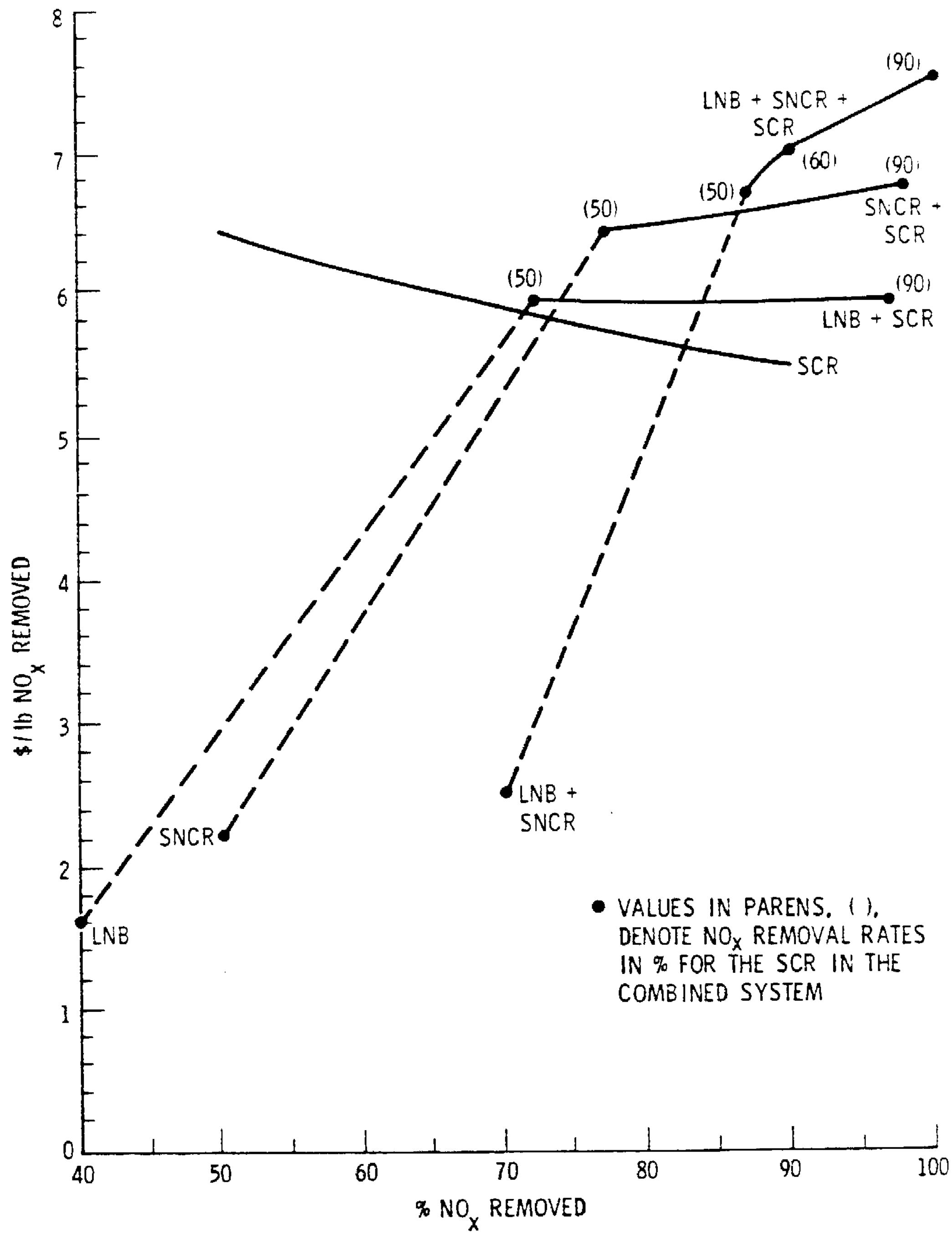


Figure 3-6 Costs of Alternative NO_x Removal Systems for a Gas-Fired 93 MMBtu/Hr Refinery Hydrotreating Heater - 72% Load with Reheat of 89°C

For all three configurations, at 90% NO_x removal, SCR alone is the most cost-effective strategy. At removal levels of 40, 50, and 70 percent, low NO_x burners, SNCR, and LNB + SNCR are the least costly alternatives, respectively, and do not involve of reheat/recovery considerations.

However, the relative cost of that level of SCR control varies depending on the amount reheat required and amount recovered. For example, Table 3-3 shows that 89°C reheat for 90% removal increases the cost of control from \$2.85/lb to \$4.38/lb (Δ\$ = \$1.53/lb) NO_x removed. This increase can be partially offset by employing reheat (65% thermal recovery), thus, improving the cost-effectiveness to \$4.22/lb NO_x removed, or a \$0.16/lb savings representing a 2.1 yr simple payback period over the case of no recovery. The cost-effectiveness of 90% control is further degraded to \$5.49/lb at 72% load without reheat/recovery and is adversely affected by the addition of reheat/recovery equipment, i.e. \$5.87/lb. This effect is graphically represented in Figure 3-7 where cost-effectiveness is plotted as a function of heater operating load. Also shown are the costs at 100% load for NO_x removal levels of 50 and 60%.

Capital and annual costs, retrofit factors, and SCR catalyst volumes for alternate levels of control are presented in Tables A-7 through A-15 in Appendix A. For 90% NO_x removal, 233 ft^3 of catalyst would be required and could be accomodated in a 502 ft^3 reactor volume.

3.1.3 115 MMBtu/Hr. Hydrocracker Stabilization Reboiler

3.1.3.1 Characteristics

This unit, manufactured by Econotherm, is a vertical cylindrical type heater utilizing 12 John Zink DBA-20 upward firing natural draft burners. The firebox heat release rate is 15,000 Btu/ft^3 - hr.

Figure 3-8 summarizes the characteristics of the 115 MMBtu/Hr reboiler operating at approximately 90% of design load (103 MMBtu/hr). Refinery gas (1196 Btu/SCF) is fired at the rate of 1440 SCFM with 20,100 SCF air (20% excess air). These quantities correspond to an air-fuel ratio of 19.3. Temperature downstream of the combustion section reaches approximately 1470°F (799°C). Exhaust gases leave the stack at 730°F (388°C) at the rate of 21,700 SCFM, wet. At this rate, NO_x emissions are approximately 23.7 lb/hr, as NO_2 (173 ppm, 3% O_2, dry). The equivalent NO_x emission factor is 0.230 lb/MMBtu at 90% load. SO_2 and particulate emissions are negligible.

3.1.3.2 Cost Estimates

Figure 3-9 illustrates the cost-effectiveness of alternative NO_x control methods for the reboiler operating at 90% load no exhaust gas reheat being applied. These curves indicate that above

TABLE 3-3

NO_x REMOVAL COST SUMMARY FOR AN SCR INSTALLATION ON A GAS-FIRED 93 MMBTU/HR REFINERY HEATER (1981 DOLLARS)

LOAD, %	NO_x REMOVAL, %	REHEAT	REHEAT RECOVERY	$/lb	COST OF REHEAT, $/lb	REHEAT RECOVERY BENEFIT, $/lb
100	90	NOT INCL.	N/A	2.85	--	--
100	70	"	"	3.15	--	--
100	60	"	"	3.35	--	--
100	50	"	"	3.61	--	--
100	90	89°C	NO	4.38	1.53	--
100	60	89°C	NO	4.88	1.53	--
100	50	89°C	NO	5.14	1.53	--
100	90	89°C	YES	4.22	--	0.16[a]
100	60	89°C	YES	4.94	--	-0.06
100	50	89°C	YES	5.26	--	-0.12
72	90	89°C	NO	5.49	--	--
72	90	89°C	YES	5.87	--	--

[a] SIMPLE PAYBACK PERIOD FOR HEAT RECOVERY: 2.1 YRS.

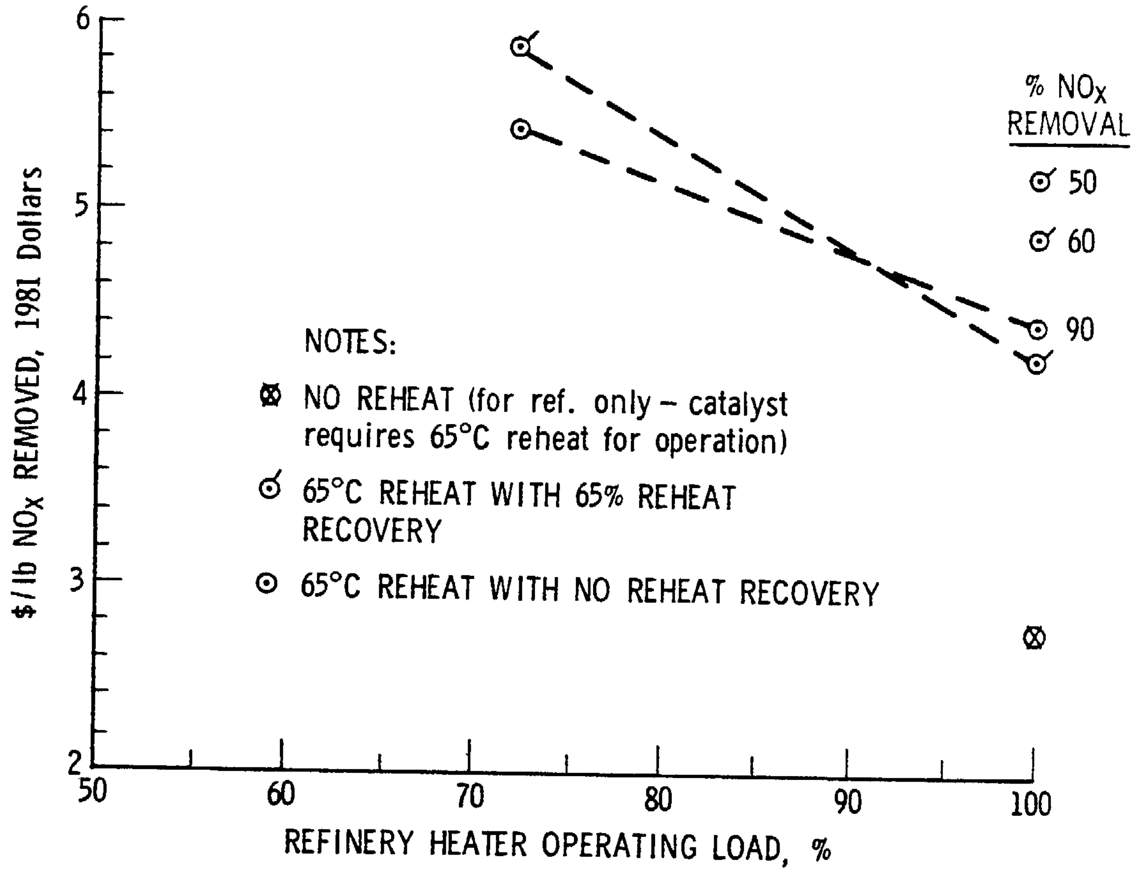
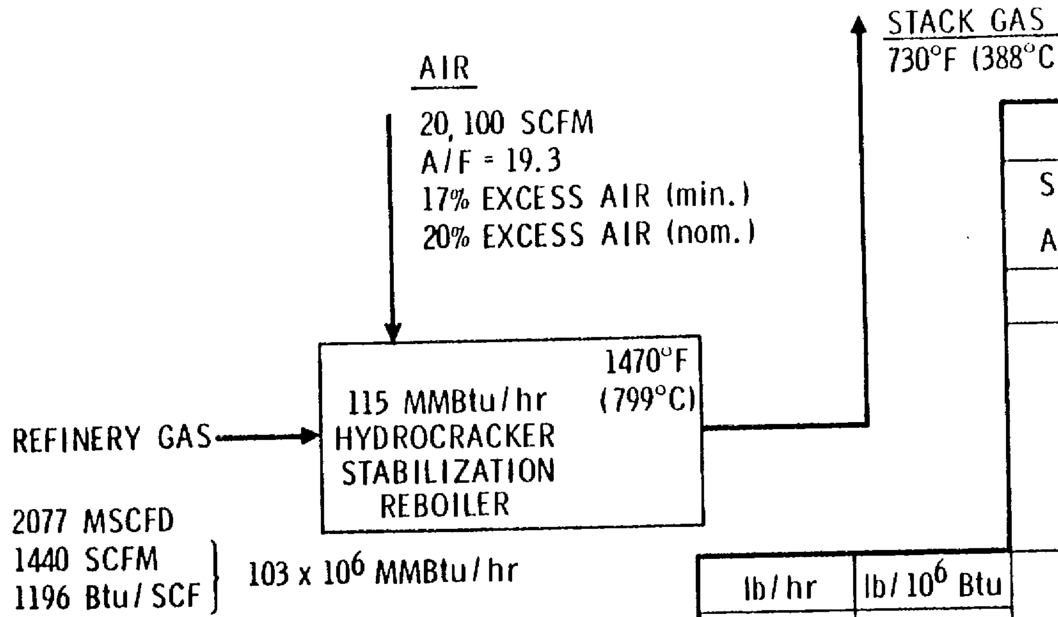


Figure 3-7 Effect of Load and Heat Recovery for an SCR Installation on a 93 MMBtu/Hr Refinery Heater



OPERATING AT APPROXIMATELY
90% OF MAX LOAD

REBOILER: ECONOTHERM VERTICAL CYLINDRICAL, NATURAL DRAFT
12 ZINK DBA-20 UPWARD FIRING BURNERS; FIREBOX HEAT RELEASE RATE: 15,000 Btu/ft^3-hr

	WET	DRY
SCFM	21,700	18,500
ACFM	52,500	44,600
	% WET	% DRY
CO_2	8.8	10.4
N_2	73.1	85.9
O_2	3.2	3.7
H_2O	14.9	0.0

lb/hr	lb/10^6 Btu		PPM, DRY
–	–	SO_2	NIL
23.7[b]	0.23[b]	NO_x	73[a]
–	–	PARTICULATES	N/A

[a] 568 lb NO_x, dry/stream day; 3% O_2, dry, in flue gas (24 hr/day)

[b] As NO_2, 90% load

Figure 3-8 Operating Characteristics of a 115 MMBtu/Hr Refinery Hydrocracker Stabilization Reboiler

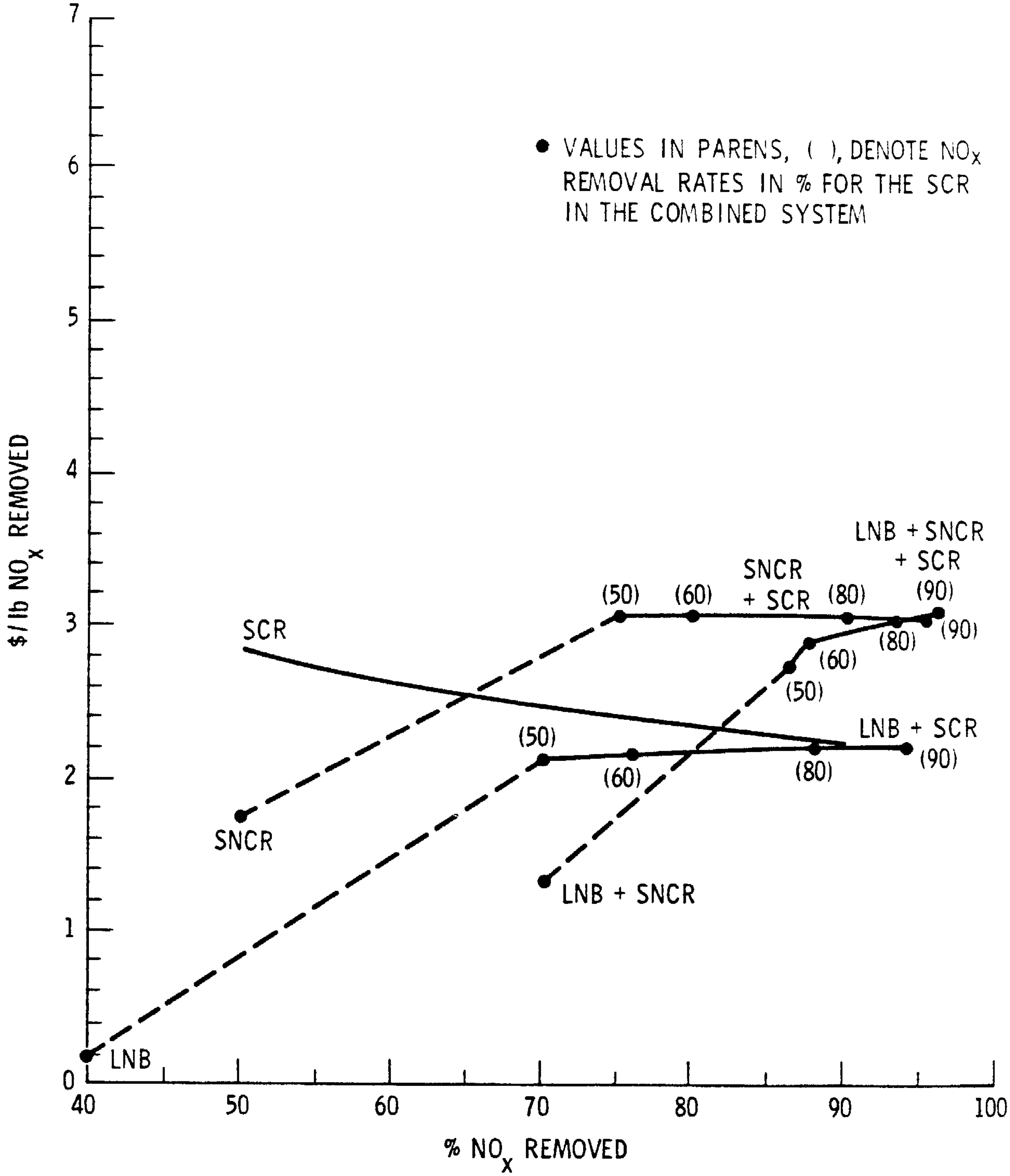


Figure 3-9 Cost of Alternative NO_x Removal Systems for a Gas-Fired 115 MMBtu/Hr Hydrocracker Stabilization Reboiler - 90% Load and No Reheat (1981 Dollars)

85% NO_x removal, SCR (only) and the combination of LNB plus SCR are relatively equivalent in cost-effectiveness. At 80% removal, the combination of LNB plus SCR has a slight advantage over SCR alone and all other combinations are not cost competitive at these removal rates.

Capital and annual cost estimates for each type of technology are given in Tables A-16 through A-21 in Appendix A. Also SCR catalyst size and reactor dimensions as a function of operating conditions is shown in Table A-19. For 90% removal 287 ft^3 of catalyst are required within a reactor approximately 1100 ft^3 in volume.

3.1.4 164 MMBtu/Hr Coke Drum Feed Heater

3.1.4.1 Characteristics

Operating characteristics of the gas-fired 164 MMBtu/hr coke drum feed heater are summarized in Figure 3-10. The unit, a Foster-Wheeler horizontal box-type heater contains 48 John Zink FFC-30A natural draft burners producing a firebox heat release rate of approximately 7525 Btu/hr-ft^3 at design capacity.

The observed operating load was at 88% of design rating; i.e., 145 MMBtu/hr. Refinery gas (1432 Btu/SCF) is combined with combustion air at an 18.2 air/fuel ratio. The rate of fuel flow is 1688 SCFM at this load. After the combustion products pass through a convection section, the flue gas exits a single stack at approximately 460°F (238°C) at a rate of 45,700 ACFM, dry (24,400 SCFM, dry). The concentration of NO_x (as NO_2) at the stack is 182 ppm, dry, at 3% O_2. This corresponds to an emission rate of 34 lb/hr and is equivalent to a 0.234 lb/MMBtu emission factor.

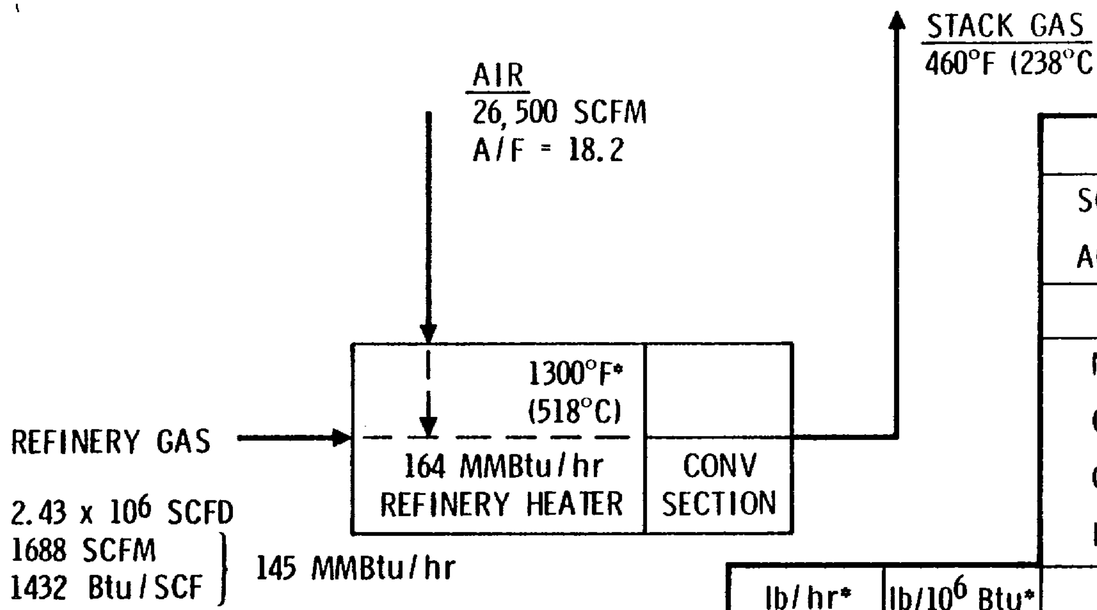
3.1.4.2 Cost Estimates

Capital investment estimates for the three individual NO_x control technologies are: $134,400 for LNB (40% NO_x removal), $497,200 for SNCR (50% NO_x removal), and $1,193,900 for SCR* at 90% NO_x removal efficiency. These estimates are based on unit operation at design capacity. Total annual costs for the system are: $43,016 for LNB, $209,000 for SNCR, and $542,900 for SCR based on the observed operating condition of the unit (88% load).

Total O&M charges for SCR amount to approximately 40% of total annual costs, for SNCR, about 29%; and for LNB, 17%. Tables A-22 through A-27 in Appendix A summarize these data and form the basis for the curves in Figure 3-11. The cost-effectiveness is depicted for alternative NO_x removal systems as a function of percent NO_x removed for the 164 MMBtu/hr coke drum feed heater at 88% load with 22°C reheat.

---

*Includes 22°C reheat



	WET	DRY
SCFM	28,550	24,400
ACFM	53,400	45,700
	% WET	% DRY
N_2	73.3	85.7
CO_2	9.7	11.4
O_2	2.5	2.9
H_2O	14.5	0.0

lb/hr*	lb/10^6 Btu*		PPM, DRY
–	–	SO_2	NIL
34.0	0.234	NO_x	182[a]
–	–	PARTICULATES	N/A

*88% load, 3% O_2, dry as NO_2

[a]34.0 lb/hr @ 145 MMBtu/hr based on 38.5 lb/hr @ 164 MMBtu/hr (3% O_2, dry)

OPERATING AT APPROXIMATELY 88% OF MAXIMUM LOAD

HEATER: HORIZONTAL BOX TYPE-FOSTER WHEELER
*ARCH TEMPERATURE
48 ZINK FFC-30 A BURNERS
FIREBOX HEAT RELEASE: 7525 Btu/hr-ft^3 (design)

Figure 3-10 Operating Characteristics of a Gas-Fired 164 MMBtu/Hr Refinery Heater

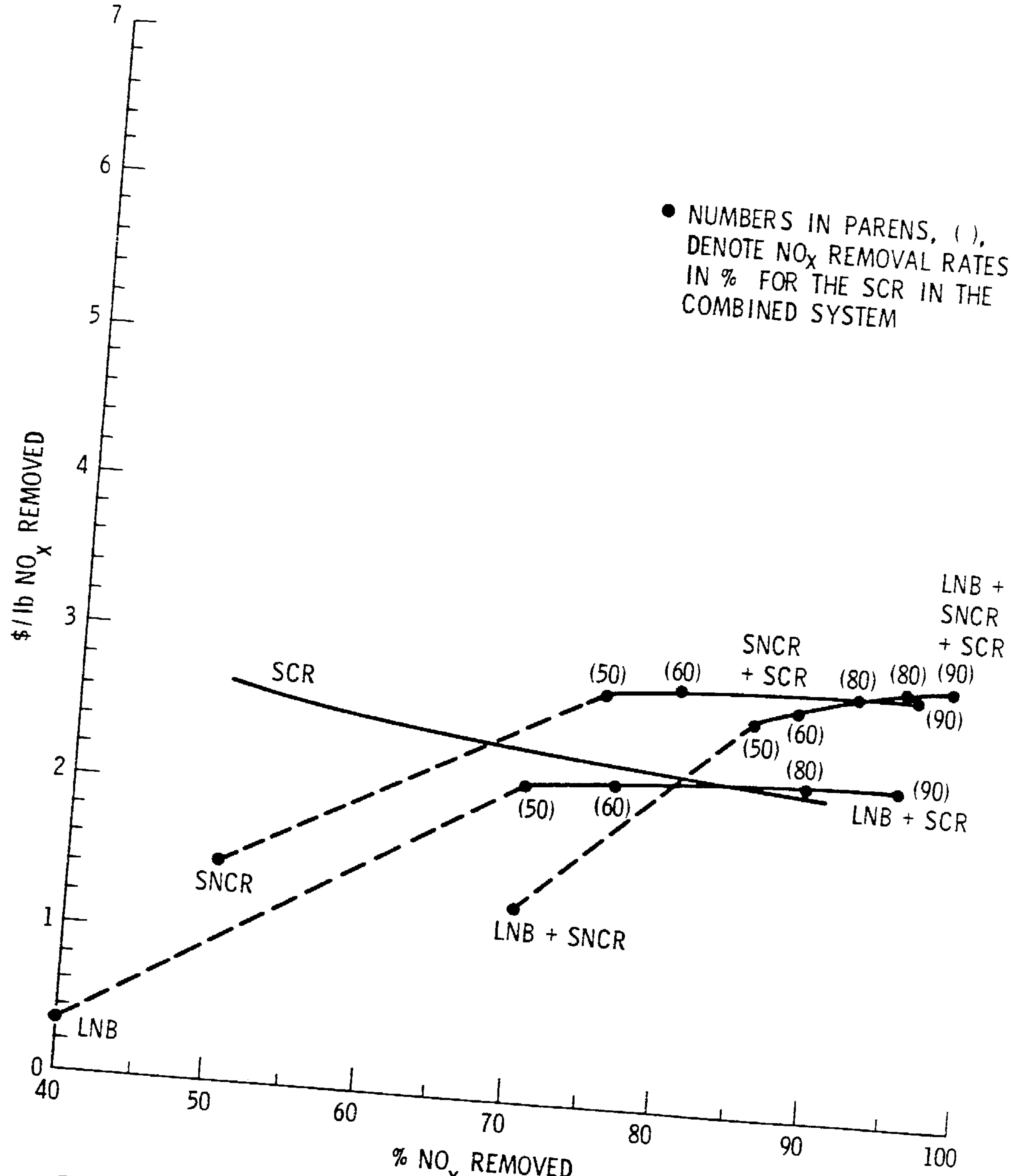


Figure 3-11 Cost of Alternative NO_x Removal Systems for a Gas-Fired 164 MMBtu/Hr Coke Drum Feed Heater - 88% Load with 22°C Reheat Without Reheat Recovery (1981 Dollars)

In general above 75% removal, the combination of LNB plus SCR is relatively equivalent in cost-effectivness with SCR alone, Figure 3-11. For example, at 90% removal, the cost of SCR alone is \$2.16/lb NO_x removed and for the combination LNB plus SCR, \$2.22/lb NO_x removed. Below that level, at 70%, LNB plus SCR is less costly than SCR; at 50%, SNCR alone appears best; and at 40%, LNBs alone are preferable. Other combinations are not competitive at any removal rate with either SCR or LNB combined with SCR.

The operating characteristics of this unit require 22°C reheat of the exhaust gas to bring the gas temperature to that needed to catalyze the reaction. However, a portion of that heat may be recovered. With an estimated 65% of the reheat recovered, a savings of \$0.01/lb NO_x removed results (compared to a case where none of the heat due to reheat is recovered). Using simple payback analysis, 2.1 years would be required to recover the cost of heat recovery equipment (see Table 1-4).

3.1.5 435 MMBtu/hr Hydrogen Reforming Heater

3.1.5.1 Characteristics

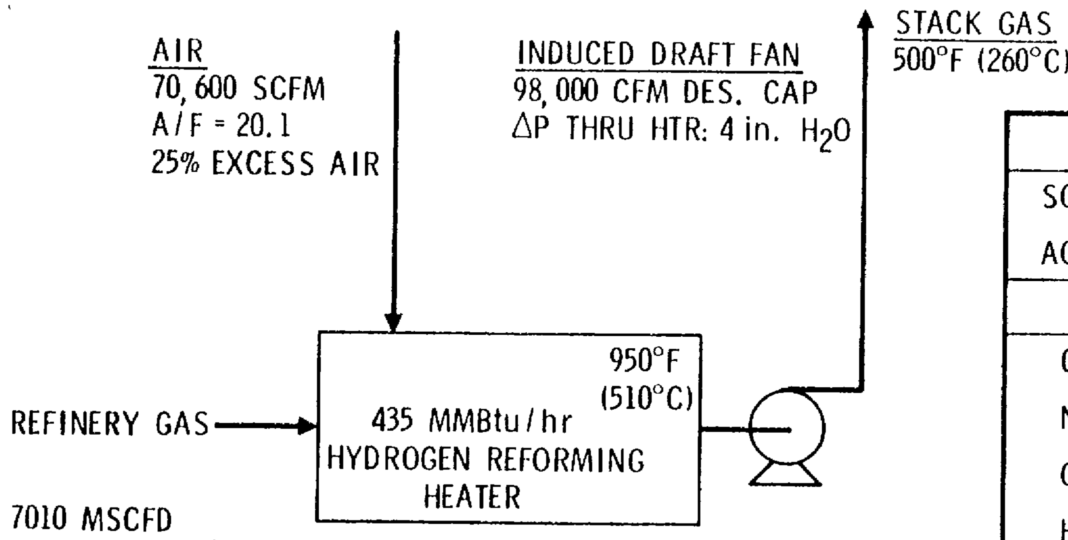
Figure 3-12 summarizes the operating characteristics of a 435 MMBtu/hr Foster-Wheeler hydrogen reforming heater a 80% of design capacity (348 MMBtu/hr). The unit is a vertical, box-type heater, induced draft, and utilizes 136 John Zink CO-33-40 horizontally fired natural draft burners. Combustion takes place at a 20.1 air/fuel ratio with 1196 Btu/SCF refinery gas being supplied at a rate of approximately 4870 SCFM and combined with 70,600 SCFM air (25% excess air). Flue gas leaves the stack at approximately 500°F (260°C) at a rate of 127,100 ACFM, dry (65,100 SCFM, dry).

Concentration of NO_x, as NO_2, in the flue gas averages 151 ppm (71.25 lb/hr or 0.205 lb/MMBtu), at 3% O_2 at 80% load. Particulate and SO_x emissions are negligible.

3.1.5.2 Cost Estimation

Figure 3-13 depicts the cost-effectiveness of alternative NO_x removal strategies as a function of percent NO_x removed from the gas-fired 435 MMBtu/hr heater operating at 80% load. Above approximately 80% NO_x removal, both SCR and the combination LNB plus SCR are competitive in terms of cost-effectiveness; from 70% to approximately 90% removal the combination LNB plus SCR appears less costly.

At 80% load, the capital investment for SCR operating at a 90% NO_x removal rate was estimated at \$2,655,600. Reheat is not required since the stack temperature, 260°C, is within the process vendors stated operating constraints (Reference 3-1).



7010 MSCFD
4870 SCFM } 348 MMBtu/hr
1196 Btu/SCF

OPERATING AT 80% OF MAXIMUM
DESIGN CAPACITY

HEATER: VERTICAL BOX TYPE
FOSTER WHEELER INDUCED DRAFT
136 ZINK CO-33-40 HORIZONTALLY
FIRED BURNERS

	WET	DRY
SCFM	76,100	65,100
ACFM	148,500	127,100
	% WET	% DRY
CO_2	8.5	9.9
N_2	73.4	85.6
O_2	3.8	4.5
H_2O	14.3	0.0

lb/hr	lb/10^6 Btu		PPM, DRY
–	–	SO_2	NIL
71.25[b]	0.205[b]	NO_x	151[a]
–	–	PARTICULATES	N/A

[a] 3% O_2, dry based on 1710 lb, dry/stream day

[b] 3% O_2, as NO_2, 80% load

Figure 3-12 Operating Characteristics of a 435 MMBtu/Hr Hydrogen Reforming Heater

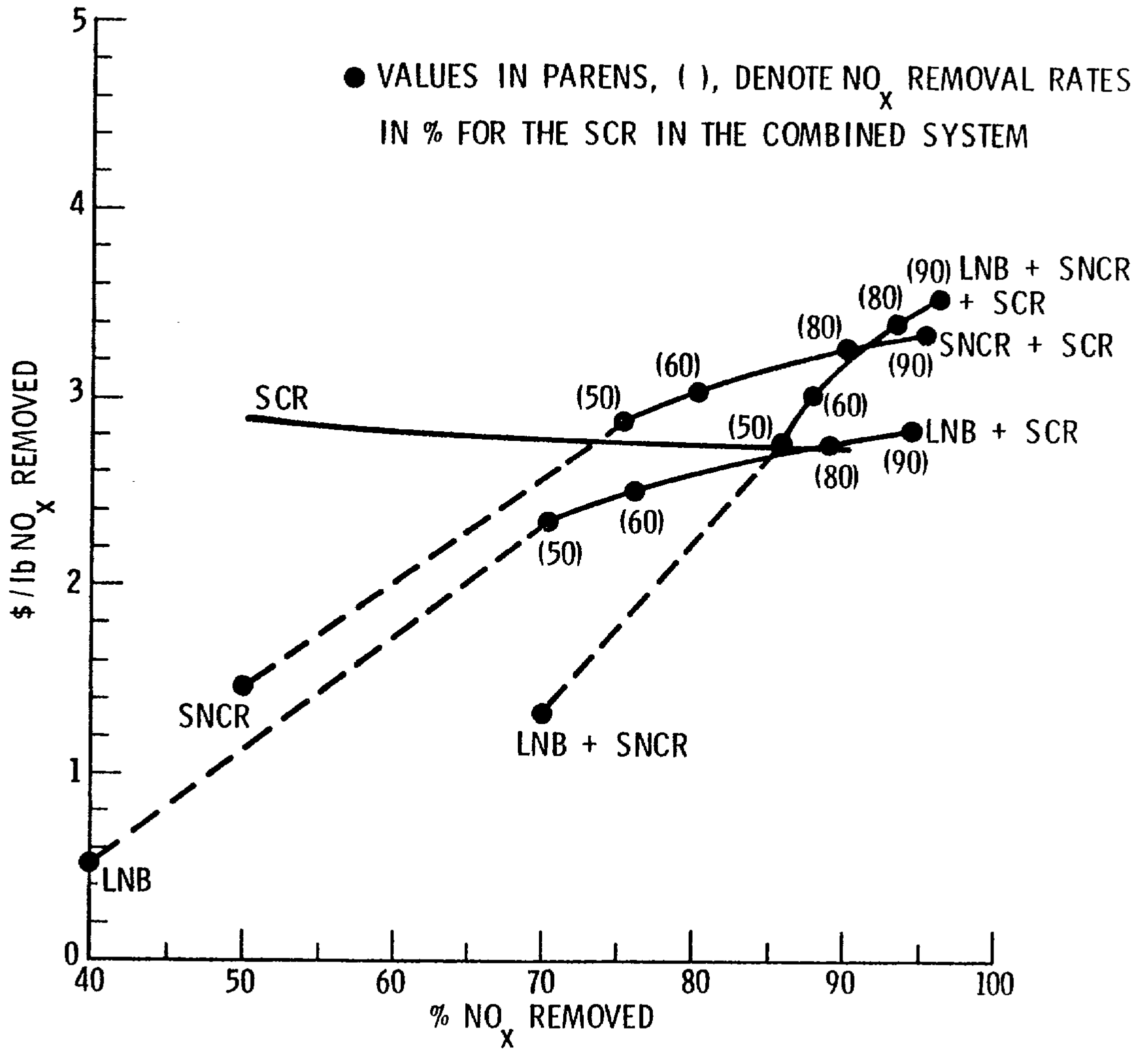


Figure 3-13 Cost of Alternative NO_x Removal Strategies for a Gas-Fired 435 MMBtu/Hr Hydrogen Reforming Heater - 80% Load (1981 Dollars)

SCR costs are relatively high due primarily to the size of the heater, large flue gas volume that must be treated, and consequently, large catalyst and reactor volume required; i.e., 1550 ft^3 of catalyst and reactor volume of 2891 ft^3 (see Table A-31, Appendix A). Retrofit costs are estimated as 15% of capital equipment and engineering/contingency costs, or as 12% of the cost of a new installation.

For SCR, annual O&M costs are estimated at approximately 49% of total annual costs ($1,414,900) at the 90% removal level. For the 136 burners required, the total capital cost estimate for LNB's is approximately $376,100 excluding engineering/contingency, retrofit, plus miscellaneous charges.Annual costs for LNB is approximately $120,390 of which O&M costs account for 15% of the total annual changes.

Capital and O&M cost estimates for SNCR and other combinations shown in Figure 3-13 are listed in Tables A-28 through A-33, Appendix A.

At a 90% removal rate, cost-effectiveness estimates for SCR and the combination LNB plus SCR are in the range of $2.74-2.84/lb NO_x removal and at 80% removal, costs range from $2.76-2.60/lb NO_x removed. At 70% removal LNB plus SCR cost-effectiveness is about $2.35/lb and for SCR is about $2.79/lb.

3.2 Industrial Boilers

3.2.1 4 MMBtu/Hr Hot Water Boiler

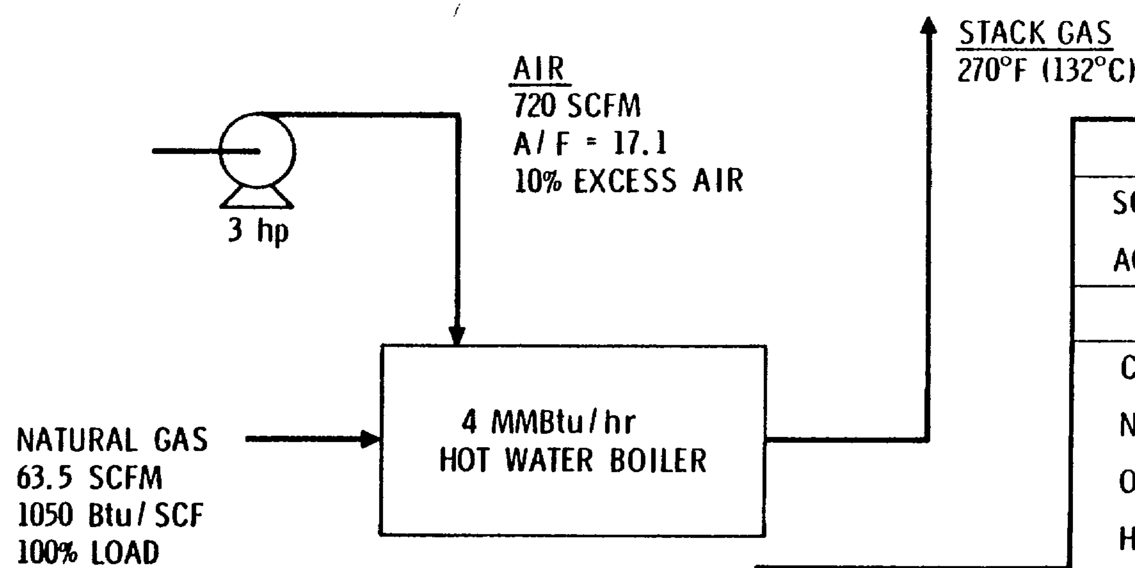
3.2.1.1 Characteristics

Characteristics of a 4 MMBtu/hr hot water boiler operating at 100% of design capacity are depicted in Figure 3-14. The unit is an Ajax packaged steam boiler, SGOX 4000, and utilizes one Ray PCPF-5 forced draft burner. Combustion is regulated at 10% excess air with an air/fuel ratio of 17.1; i.e., 63.5 SCFM natural gas (1050 Btu/SCF) is burned with 720 SCFM air. The resultant flue gas leaves the stack at a volumetric rate of 1195 ACFM, wet (805 SCFM, wet) or 995 ACFM, dry (670 SCFM, dry) and at a temperature of 270°F (132°C).

The concentration of NO_x in the flue gas is estimated at 75 ppm, dry, at 3% O_2 or 0.4 lb/hr (0.1 lb/MMBtu) as NO_2. Particulate and SO_x emissions are negligible.

3.2.1.2 Cost Estimates

Cost-effectiveness of alternative NO_x control strategies for the 4 MMBtu hot water boiler operating at 100% load are depicted in Figure 3-15. The magnitude of NO_x emissions is relatively low for this unit (i.e., 0.4 lb/hr) and the annual cost of control



	WET	DRY
SCFM	805	670
ACFM	1195	995
	% WET	% DRY
CO_2	9.1	10.9
N_2	72.2	86.7
O_2	2.0	2.4
H_2O	16.7	0.0

lb/hr	lb/10^6 Btu		PPM, DRY
–	–	SO_2	NIL
0.4[b]	0.1[b]	NO_x	75[a]
–	–	PARTICULATES	N/A

[a] 3% O_2, dry

[b] As NO_2

HOT WATER BOILER: AJAX PACKAGED BOILER
SGOX 4000
ONE RAY PCPF-5 BURNER

Figure 3-14 Operating Characteristics of a Gas-Fired 4 MMBtu/Hr Industrial Boiler

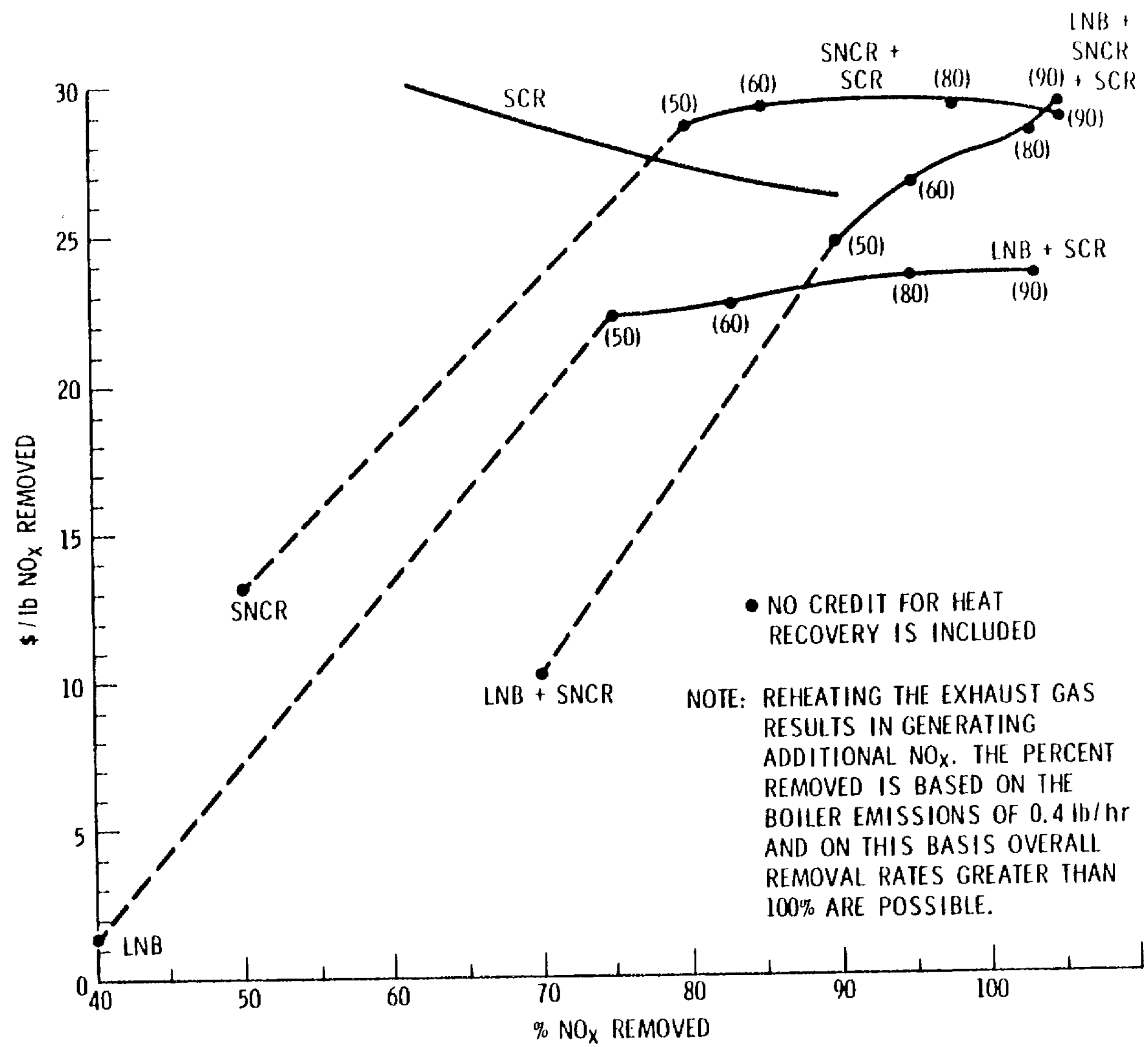


Figure 3-15 Cost of Alternative NO_x Control Systems for a Gas-Fired 4 MMBtu/Hr Industrial Boiler - 100% Load and 128°C Reheat

systems is high relative to larger units that have correspondingly higher NO_x emissions, thereby resulting in a high $/lb removal cost. Thus, in this particular case, because of its small size, the cost for 90% removal of NO_x with SCR is $26.00/lb. This includes a catalytic reactor with a volume of approximately 74 ft^3 containing 9.3 ft^3 of catalyst. For SNCR with an estimated 50% removal, the cost is approximately $13.20/lb of NO_x removed. Estimates for other combinations are given in Tables B-1 through B-6 in Appendix B.

In terms of cost-effectiveness, a reasonable strategy to reduce emissions appears to be the use of LNB at the 40% removal level, which could be expected to be accomplished at a cost of $1.30/lb NO_x removed. Such a LNB installation would require a total capital investment of approximately $3900. Total annual costs for the burner are estimated at $1240.

3.2.2 22 MMBtu/hr Hot Water Boiler

3.2.2.1 Characteristics

The operating characteristics of a 22 MMBtu/hr C-E Lamont industrial hot water boiler operating at 52% (11.4 MMBtu/hr) of rated load as summarized in Figure 3-16. The unit has one forced draft Peabody air atomizing ring type burner which can be utilized for either gas or oil-firing.

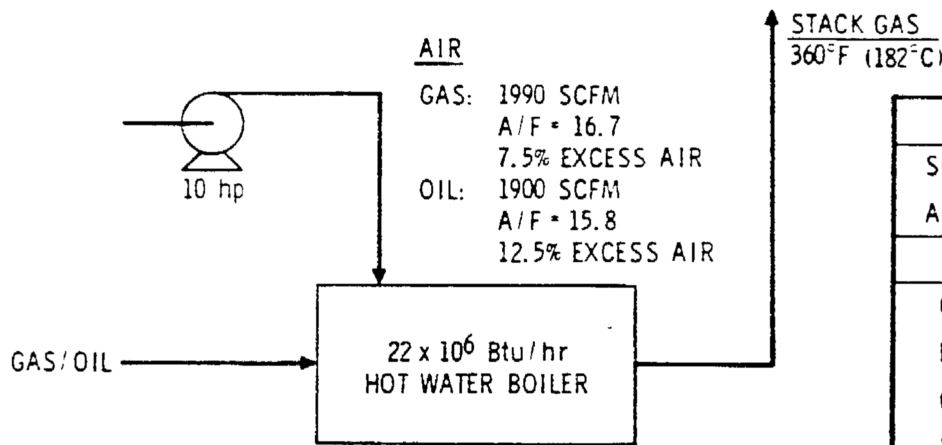
Under oil-fired conditions, 19,000 Btu/lb No. 2 fuel oil is combusted with 1900 SCFM air at an air/fuel ratio of 15.8 (12.5% excess air). The resulting flue gas leaves the stack at a volumetric rate of 3294 ACFM, wet (1976 SCFM, wet) at approximately 360°F (182°C).

For gas-fired operation, natural gas (approximately 1058 Btu/SCF) and 1990 SCFM air are combined and burned at a 16.7 air/fuel ratio (7.5% excess air). The rate of flue gas leaving the stack is 3663 ACFM, wet (2199 SCFM, wet) at a temperature of 360°F (182°C).

At 52% load NO_x emissions are 5.5 lb/hr (367 ppm, dry, at 3% O_2) for oil-firing and 1.93 lb/hr (137 ppm, dry, at 3% O_2) for gas-firing. NO_x emission factors for oil and gas, respectively, are 0.48 lb/MMBtu and 0.17 lb/MMBtu. SO_2 and particulate emissions are negligible for gas-firing, but for oil-firing SO_2 can be expected in concentrations of approximately 194 ppm, dry (4.22 lb/hr or 0.37 lb/MMBtu) and particulates approximately 0.331 ppm, dry (5.53 lb/hr or 0.49 lb/MMBtu).

3.2.2.2 Cost Estimates

Figures 3-17 and 3-18 illustrate the cost-effectiveness of alternative NO_x removal systems as a function of percent NO_x removed from an oil or gas-fired 22 MMBtu/Hr industrial hot water boiler operating at 52% load. Since this unit utilizes both gas



180 SCFM GAS
9.7 lb/min OIL } 11.4 x 10^6 Btu/hr

GAS: 1058 Btu/SCF
OIL: 19,000 Btu/lb

CONDITIONS AT APPROXIMATELY
52% OF RATED LOAD

HOT WATER BOILER: C-E LAMONT, FORCED DRAFT,
ONE AIR ATOMIZING, RING TYPE PEABODY BURNER

GAS

	WET	DRY
SCFM	2,199	1,831
ACFM	3,663	3,051
	% WET	% DRY
CO_2	9.30	11.22
N_2	72.03	86.87
O_2	1.59	1.91
H_2O	17.08	0.0

lb/hr	lb/10^6 Btu		PPM, DRY
–	–	SO_2	NIL
1.93[b]	0.17[b]	NO_x	137[a]
–	–	PARTICULATES	N/A

OIL

	WET	DRY
SCFM	1,976	1,949
ACFM	3,294	3,248
	% WET	% DRY
CO_2	12.37	13.89
N_2	74.49	83.62
O_2	2.20	2.47
H_2O	10.92	0.0
SO_2	0.02	0.02

lb/hr	lb/10^6 Btu		PPM, DRY
–	–	SO_2	194
5.5[b]	0.48[b]	NO_x	367[a]
5.53	0.49	PARTICULATES	0.331[c]

[a] 3% O_2 [b] As NO_2 [c] Grains/SCF (757 mg/Nm^3)

Figure 3-16 Operating Characteristics of a 22 MMBtu/Hr Industrial Hot Water Boiler

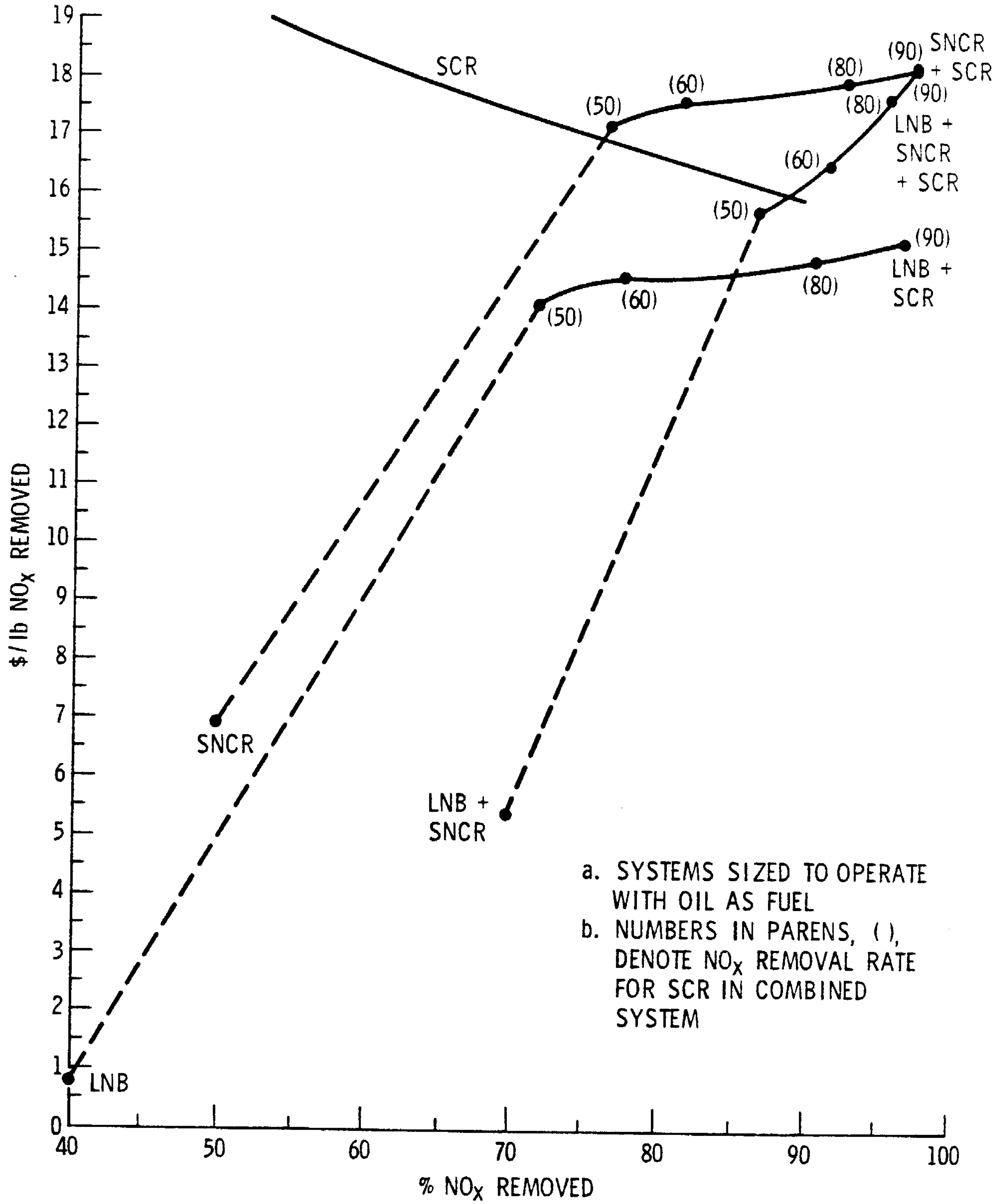


Figure 3-17 Cost of Alternative NO_x Removal Systems for a 22 MMBtu/Hr Boiler - Gaseous Fuel with 78°C Reheat at 52% Load (1981 Dollars)

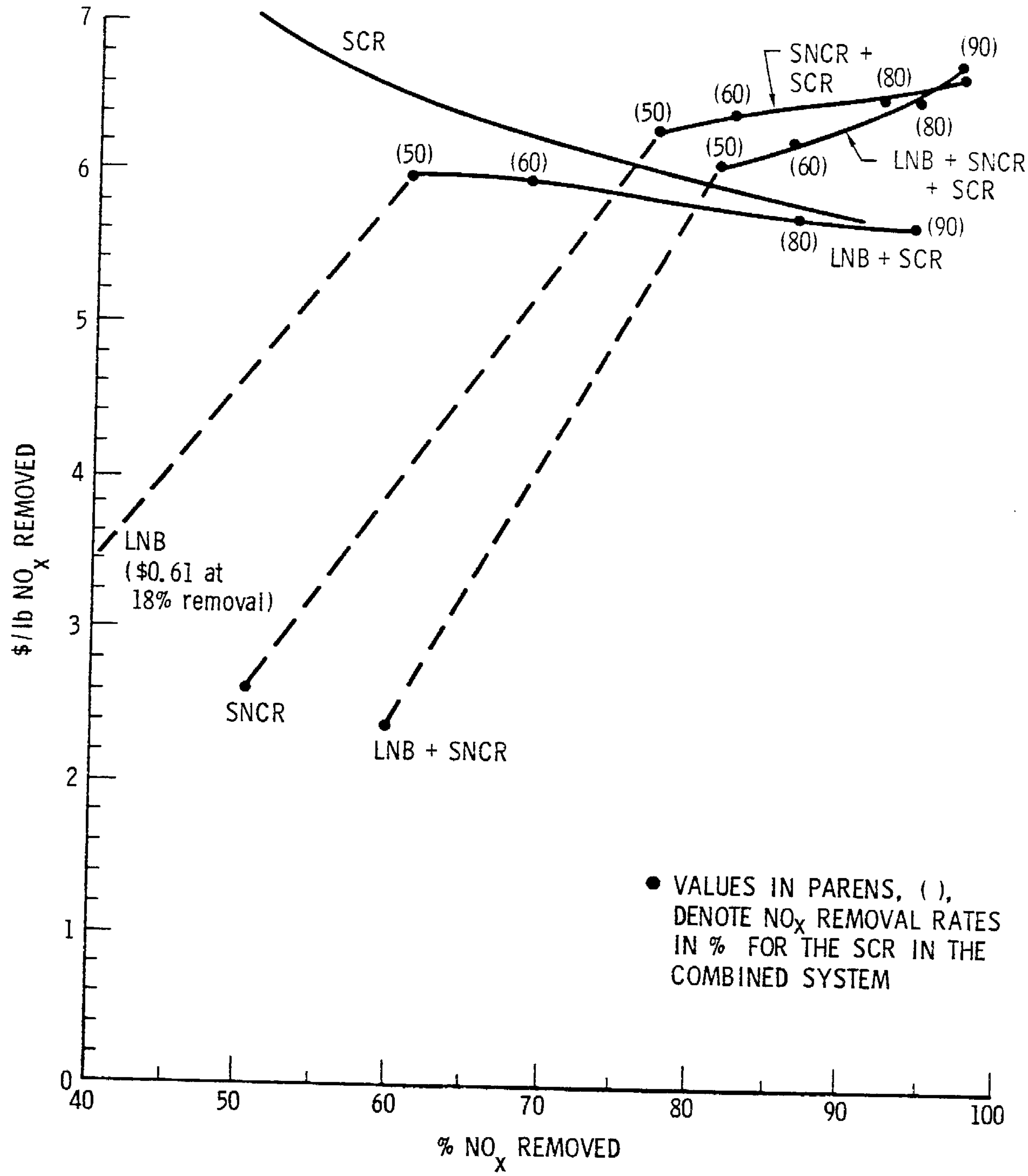


Figure 3-18 Cost of Alternative NO_x Removal Systems for a 22 MMBTU/Hr Boiler Burning Oil Fuel with 78°C Reheat at 52% Load (1981 Dollars)

and oil as fuel, these cost estimates were made based on configuring the NO_x removal equipment, specifically LNB and SCR, for the oil-fired operating conditions. Under such a basis, a catalyst/reactor could be expected to be subject to more severe operating conditions relative to particulate and SO_2 exposure.

For the two-fuel installation, the cost of NO_x removal is greater for gaseous fuel than for oil because less NO_x is normally generated from gaseous fuel (no fuel-NO_x component). The combination, LNB + SCR is generally the least expensive control alternative from 70 to 90% NO_x removal under both oil and gas-firing conditions. For example, the cost effectiveness of this installation at 90% removal is \$5.70/lb NO_x for oil fuel and \$14.80/lb when operated with gas (see Table 3-4). This performance level would necessitate a catalyst volume of 90 ft^3 housed in a 288 ft^3 reactor.

For SCR, total capital investment for a system designed to perform at 90% removal is estimated at \$451,000. This cost includes equipment for and heat exchngers for 78°C reheat an estimated 65% reheat recovery. The details of this estimate are further illustrated in Tables B-7 and B-8, Appendix B.

Total annual costs for SCR as previously described (at 52% load) are estimated at \$167,700 for gas and \$169,700 for oil with O&M costs for both configurations approximately 27% of the total annual cost.

For LNB, total capital investment for a combination burner that can fire either oil or gas is estimated at \$10,900. Consequently the total annual cost for the combined LNB + SCR system is expected to be approximately \$152,402 for gaseous fuel and \$144,902 for oil. Cost estimates for SNCR and various levels of SCR control are contained in Tables B-7 through B-13, Appendix B.

The effect of reheat required on NO_x removal cost for 90 and 50% NO_x removal for SCR operation with reheat recovery as a function of load is shown in Table 3-5 and Figure 3-19 for the boiler operating at 52% and 100% load. At 100% load using fuel oil and considering 90% NO_x removal, heating the exhaust gas to increase its temperature 78°C increases the \$/lb NO_x cost from \$2.84 to 4.02/lb. The 78°C reheat provides the temperature which is required for use with the catalyst. However, with 65% reheat recovery, the cost of reheat increases from \$2.84 to \$3.59. Thereby a \$0.43/lb savings (\$4.02-\$3.59) can be attributed to heat recovery. Similarly, for 100% load utilizing gaseous fuel and 90% NO_x removal, the cost increases from \$8.87/lb for no reheat to \$10.93/lb with 78°C reheat/recovery a \$1.07 savings is realized with 65% heat recovery. At 52% load and for 90% NO_x removal, a \$0.03/lb savings is realized using reheat recovery with fuel oil and a \$0.14/lb savings results from using reheat recovery with gaseous fuel. It must be noted that the costs provided for "no-reheat" conditions are for reference only, inasmuch as the catalyst would be virtually ineffective at the temperature conditions without reheat.

TABLE 3-4

NO_x REMOVAL COSTS FOR ALTERNATIVE CONTROL SYSTEMS RESULTING FROM THE USE OF NATURAL GAS IN A BOILER WITH ABATEMENT SYSTEMS SIZED FOR OIL - 22 MMBTU/HR BOILER WITH $78^{o}C$ REHEAT

FUEL	TOTAL COST, \$/LB NO_x REMOVED[a]			
	SCR	LNB+SCR	SNCR+SCR	LNB+SNCR+SCR
OIL	5.80	5.70	6.60	6.50
NAT GAS	16.00	14.80	17.80	16.30

[a] 90% REMOVAL, 52% LOAD

TABLE 3-5

EFFECT OF REHEAT AND REHEAT RECOVERY ON
THE NO_x REMOVAL COST OF AN SCR INSTALLATION ON
A 22 MMBTU BOILER AT TWO OPERATING LOADS

NO_x REMOVAL %	LOAD %	OIL			GAS		
		WITHOUT REHEAT (BASELINE)	WITH 78°C REHEAT, NO RECOVERY	WITH REHEAT & 65% RECOVERY	WITHOUT REHEAT	WITH 78°C REHEAT	WITH REHEAT & 65% RECOVERY
90	100	2.84	4.02	3.59	8.87	10.93	9.86
90	52	--	5.80	5.83	--	16.00	16.14
50	52	--	--	7.56	--	--	21.00

*FOR REFERENCE ONLY - CATALYST INOPERABLE AT GAS TEMP. WITHOUT REHEAT

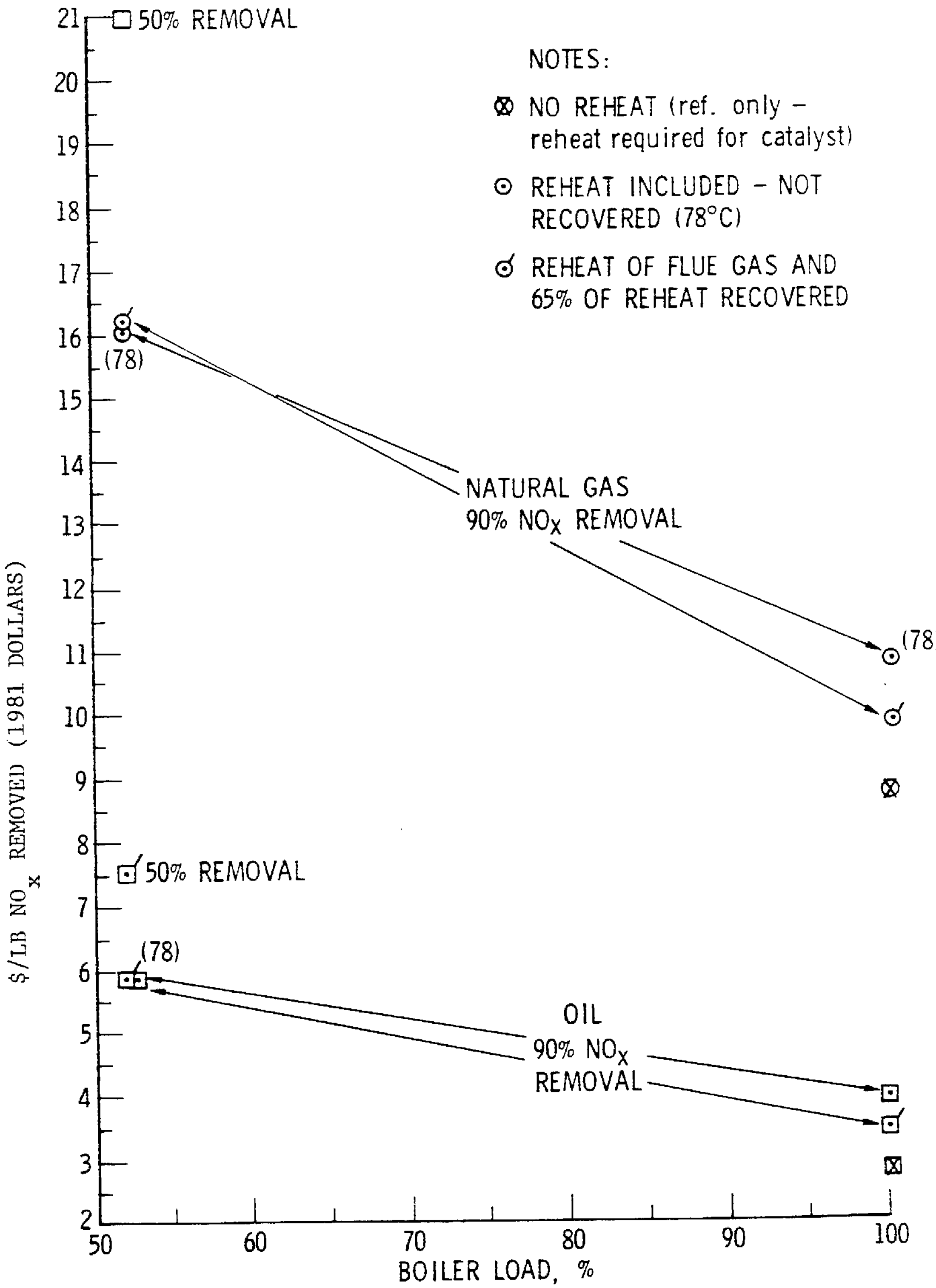


Figure 3-19 Effect of Reheat and Reheat Recovery on the NO_x Removal Cost of an SCR Installation on a 22 MMBtu/hr Industrial Boiler

3.2.3 150 MMBtu/Hr Steam Boiler

3.2.3.1 Characteristics

Figure 3-20 summarizes the operating characteristics of a 150 MMBtu/hr Babcock & Wilcox, Type FM, vertical tube industrial steam boiler which is nominally rated at 125,000 lb/hr, 150 psi steam. One Babcock & Wilcox forced draft horizontally-fired burner is utilized. The unit was observed operating at 48% of design load (72 MMBtu/hr) and firing No. 2 fuel oil (19,000 Btu/lb) at a rate of 63.2 lb/min with 15% excess air (air/fuel = 17.8). Combustion products enter the stack at approximately 450°F (232°C) and are exhausted at a volumetric flow rate of 27,100 ACFM, wet.

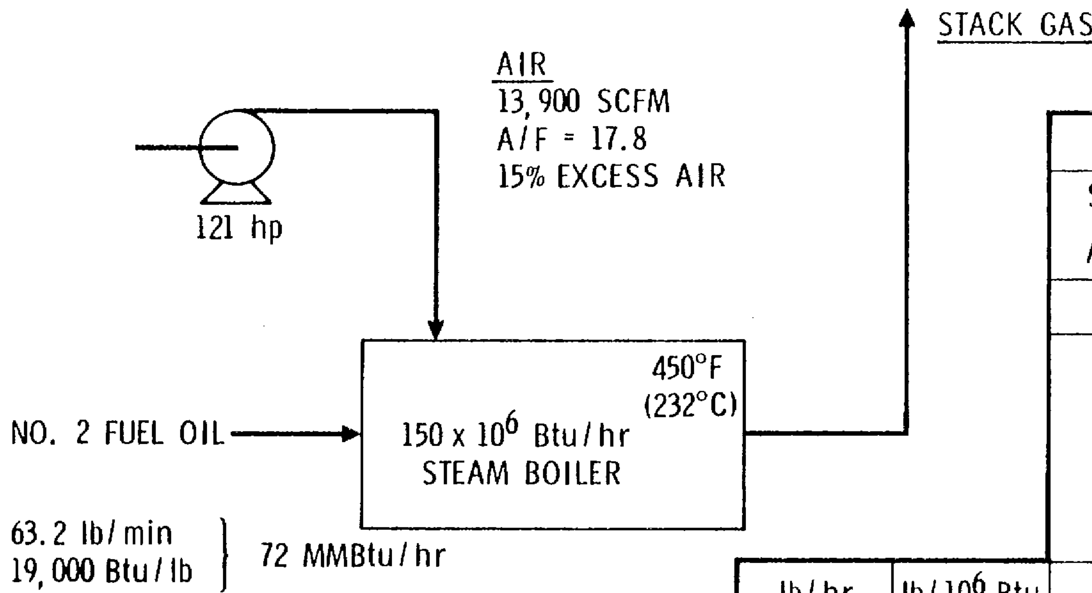
NO_x emissions, as NO_2, were estimated using emission factors to be approximately 9.4 lb/hr (103 ppm, dry at 3% O_2) at 48% load. This is equivalent to an emission rate of 0.13 lb/MMBtu - actual test data were not available. SO_2 emissions, using No. 2 fuel oil, can be expected to be 0.95 lb/hr (7.4 ppm, dry) and particulate emissions, about 3.8 lb/hr (0.037 grains, std. cu. ft., dry).

3.2.3.2 Cost Estimation

Costs were estimated for various NO_x control strategies applied to a 150 MMBtu/hr industrial steam boiler operating at 100% load with reheat and reheat recovery equipment. Also, estimates were prepared for SCR alone at 75 and 50% load in order to illustrate the effect of boiler operating load on NO_x removal costs.

Figure 3-21 depicts the cost-effectiveness of alternative NO_x removal systems as a function of percent NO_x removal from an oil-fired 150 MMBtu/hr steam boiler operating at 100% load. The use of SCR at 75% and 50% load is also illustrated. Generally, for overall NO_x removal rates between 60 to 90% (approximately \$5.65 to \$5.35/lb NO_x removed), a combination of LNB + SCR is the most cost-effective control strategy. An exception occurs at 83% overall NO_x removal where LNB + SNCR + SCR is equivalent in cost-effectiveness to LNB + SCR (\$5.40/lb). For 59% overall removal, LNB + SNCR is the least costly alternative (\$1.65/lb); at 50%, SNCR has the lowest cost (\$1.84/lb); and at 18%, LNB is the least expensive (\$0.28/lb).

The effect of operating load on the cost of 90% NO_x removal for an SCR installation on this boiler, is illustrated in Figure 3-22. At 100% load, the cost of NO_x removal is approximately \$5.30/lb for the boiler which requires exhaust gas to be reheated 68°C. It also includes reheat recovery equipment which is estimated to recover 65% of the reheat and provides a credit of \$1.25/lb of NO_x; which results in the estimated \$5.30/lb NO_x. At 75% load, the cost of removal increases to about \$6.75/lb and at 50% load the cost increases to \$9.65/lb. Thus, costs increase significantly and non-linearly with boiler operation at reduced loads.



CONDITIONS AT APPROXIMATELY
48% OF RATED LOAD

	WET	DRY
SCFM	14,700	11,900
ACFM	27,100	22,100
	% WET	% DRY
CO_2	11.9	13.3
N_2	74.7	83.7
O_2	2.6	2.9
H_2O	10.7	0.0

lb/hr	lb/10^6 Btu		PPM, DRY
0.95	0.013	SO_2	7.4
9.4[b]	0.13[b]	NO_x	103[a]
3.8	0.053	PARTICULATES	0.037[c]

STEAM BOILER: VERTICAL TUBE, FORCED DRAFT, B&W TYPE FM,
B&W (1) HORIZONTAL BURNER
125,000 lb/hr STEAM, 150 psi

[a] 3% O_2

[b] As NO_2, 3% O_2, 48% load

[c] Grains/SCF (85.0 mg/Nm^3)

Figure 3-20 Operating Characteristics of a Gas-Fired 150 MMBtu/Hr Industrial Steam Boiler

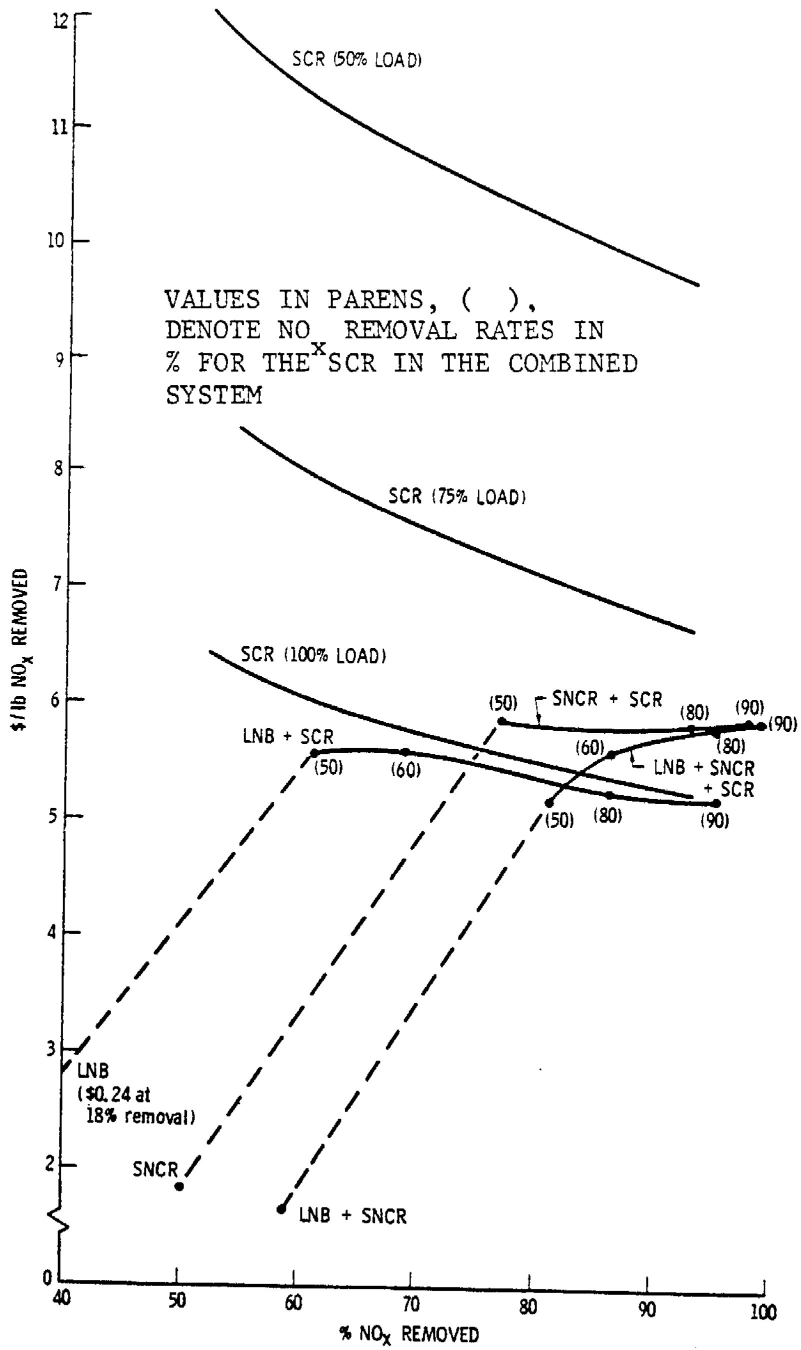


Figure 3-21 Cost of Alternative NO_x Removal Systems for an Oil-Fired 150 MMBtu/Hr Steam Boiler Operating at 100% Load - 68°C Reheat with 65% Heat Recovery (1981 Dollars)

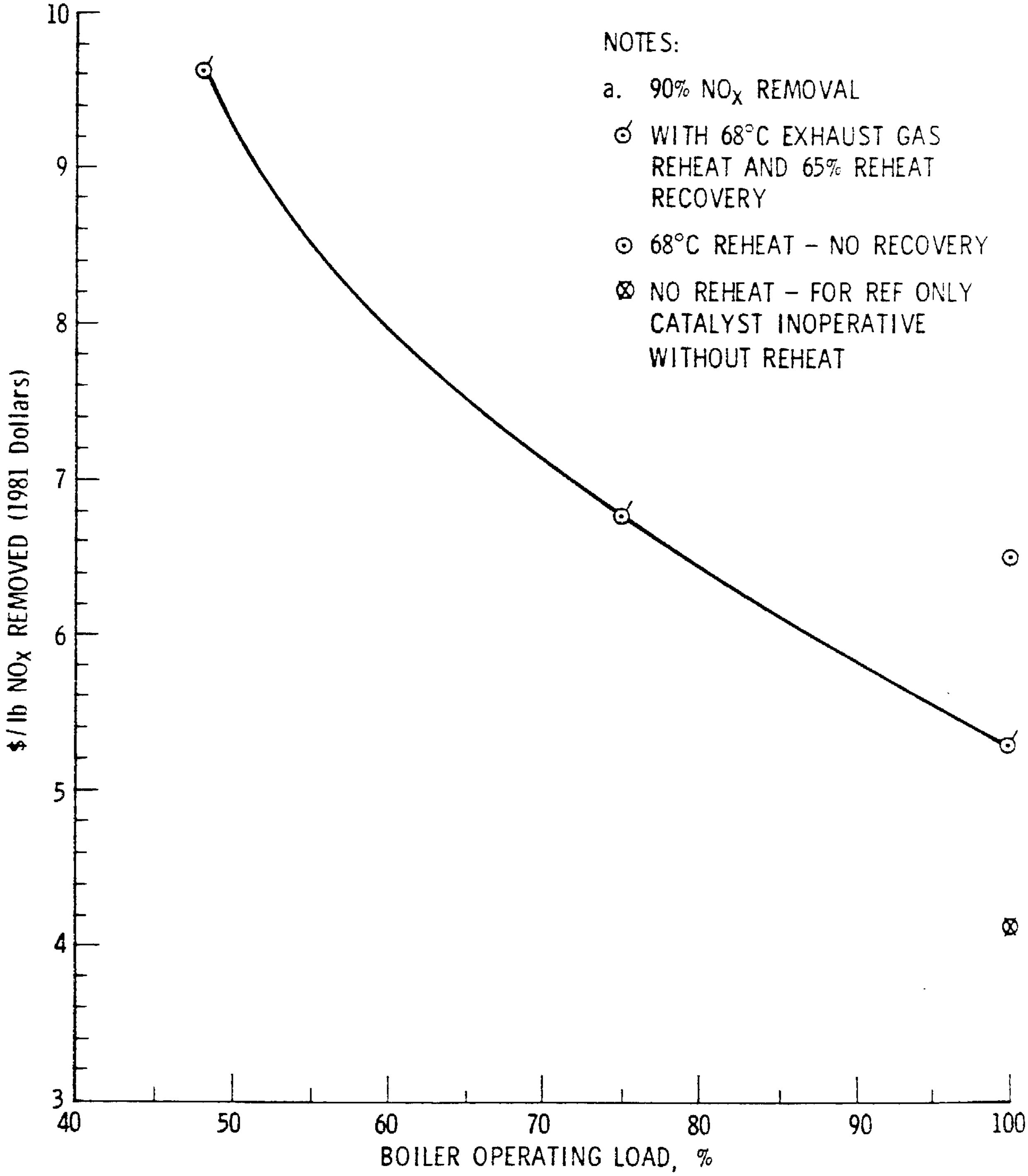


Figure 3-22 Effect of Operating Load on Cost of NO_x Removal for an SCR Installation on an Oil-Fired 150 MMBtu/Hr Industrial Boiler

Also shown in Figure 3-22 at 100% load is the effect of exhaust gas reheat and reheat recovery equipment on the cost of NO_x removal. For example, if an SCR installation could be applied to a similar sized unit without reheat being necessary, the baseline cost for SCR would be about $4.10/lb. However, including the 68°C reheat that is required for the boiler under study, the cost of NO_x removal increases to $6.55/lb. The cost of reheat can be partially offset if recovery equipment that achieves 65% thermal recovery can be installed. This results in $5.30/lb NO_x removed, or a $1.25/lb savings due to recovery.

Total capital investment for SCR equipment capable of 90% NO_x removal at 100% load is estimated at $1,542,700 which accounts for 598 ft^3 catalyst to be housed in a reactor volume of 1734 ft^3. Capital investment for smaller sized SCR units are given in Table B-15, Appendix B. For 90% NO_x removal, total O&M costs are estimated at 45% of total annual costs which are expected to be approximately $770,500.

Total annual cost of a low NO_x burner capable of 40% thermal NO_x reduction, or an estimated 18% overall reduction, is estimated at $7800 (total capital investment = $24,380).

Costs for SNCR and a detailed breakdown of component costs for other single systems and combinations are presented in Tables B-14 through B-19, Appendix B.

3.2.4 336 MMBtu/hr Process Steam Boiler

3.2.4.1 Characteristics

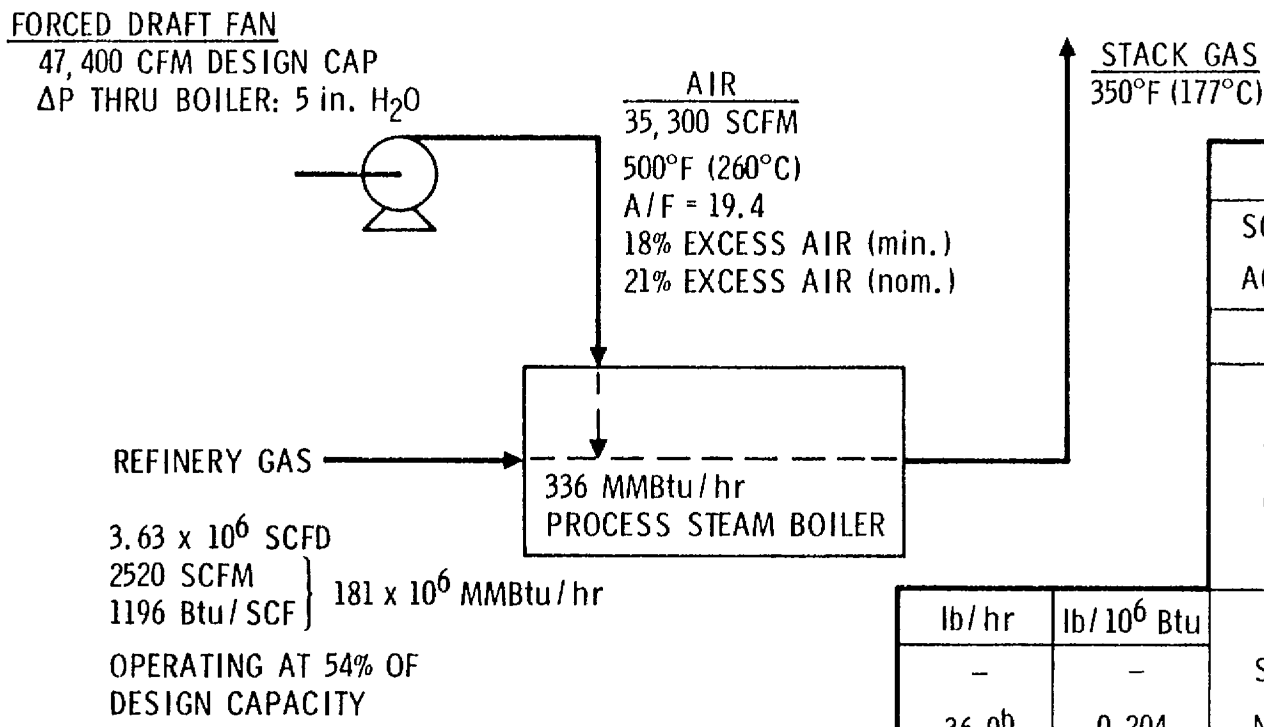
The operating characteristics of an Eric City Iron Works 336 MMBtu/hr process steam boiler rated at 220,000 lb steam per hour operating at 54 percent of design capacity (181 MMBtu/hr) are summarized in Figure 3-23. Four Peabody DWG AD-5130 horizontal forced-draft gas-firing burners are utilized. The unit is characterized by a heat release rate of 47,000 Btu/hr-ft^3.

Combustion occurs at an air/fuel ratio of 19.4 where refinery gas (1196 Btu/SCF) at a rate of 2520 SCFM is mixed with 21%, 500°F (260°C), preheated excess air. Exhaust gas exits the stack at approximately 350°F (177°C) at a rate of 62,900 ACFM, wet.

NO_x, as NO_2, emissions are reported as 36.9 lb/hr or 152 ppm, dry, at 3% O_2. This emission rate is equivalent to 0.204 lb/MMBtu. SO_2 and particulate emissions are negligible.

3.2.4.2 Cost Estimates

Figure 3-24 illustrates the cost-effectiveness of alternative NO_x removal systems as a function of percent NO_x removed from a gas-fired 336 MMBtu/hr refinery process steam boiler operating at 54% load. In general, from about 70% to 95% NO_x removal, the combination of



	WET	DRY
SCFM	38,200	32,600
ACFM	62,900	53,600
	% WET	% DRY
N_2	73.2	85.9
CO_2	8.8	10.3
O_2	3.3	3.8
H_2O	14.8	0.0

lb/hr	lb/10^6 Btu		PPM, DRY
–	–	SO_2	NIL
36.9[b]	0.204	NO_x	152[a]
–	–	PARTICULATES	N/A

[a] 3% O_2, DRY
BASED ON 885 $\frac{\text{lb}}{\text{STREAM day}}$

[b] 3% O_2, AS NO_2, 54% LOAD

BOILER: PROCESS STEAM – ERIC CITY IRON WORKS
4 PEABODY (DWG AD-5130) HORIZONTAL-FIRING BURNERS
FIREBOX HEAT RELEASE CHARACTERISTICS: 47,000 $\frac{\text{Btu}}{\text{hr-ft}^3}$

Figure 3-23 Operating Characteristics for a Gas-Fired 336 MMBtu/Hr Process Steam Boiler

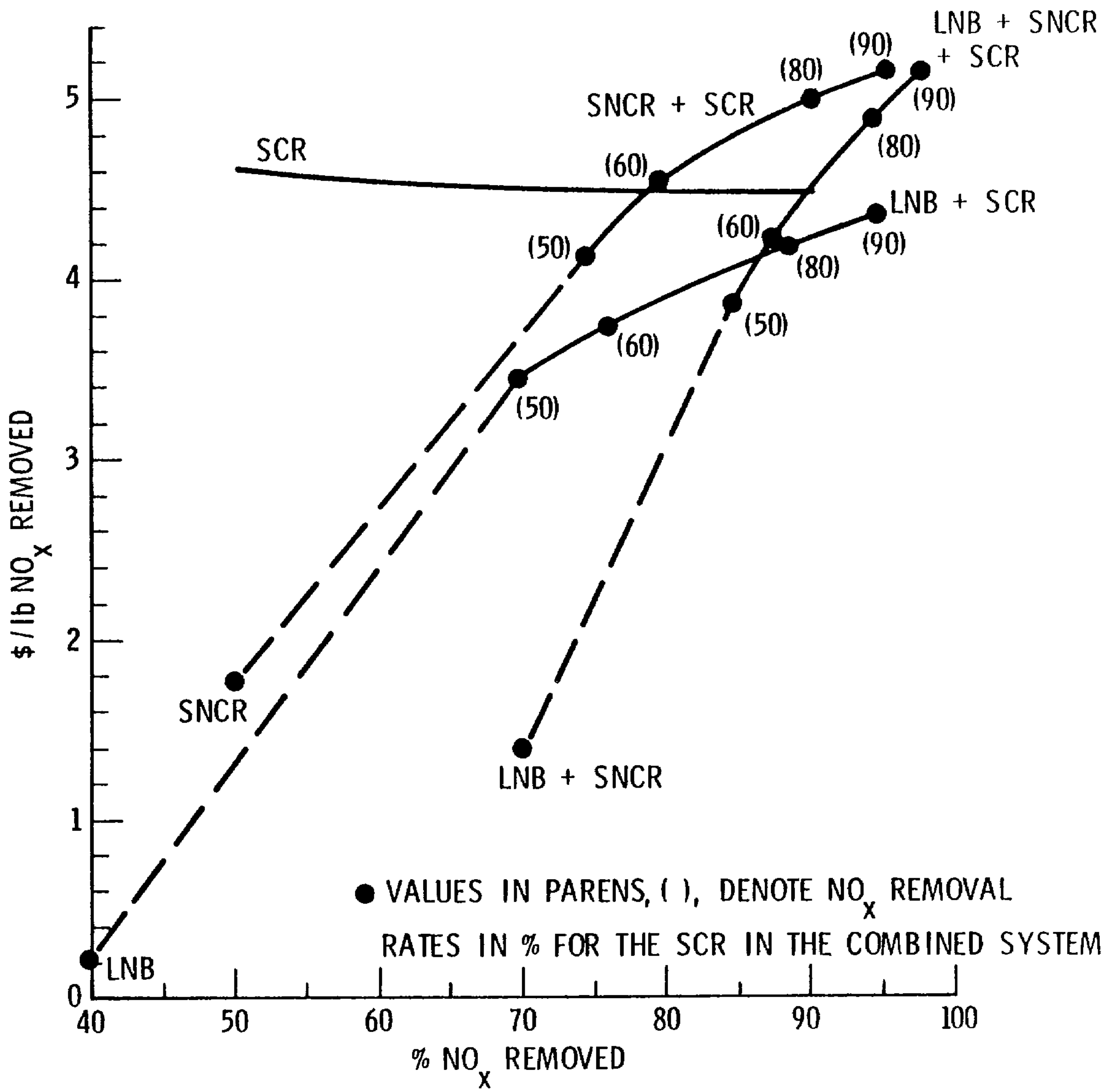


Figure 3-24 Cost of Alternative NO_x Removal Systems for a Gas-Fired 336 MMBtu/Hr Process Steam Boiler at 54% Load with 83°C Reheat with no Reheat Recovery (1981 Dollars)

LNB + SCR is less costly than any of the other alternatives. However, LNB + SNCR + SCR becomes competitive with LNB + SCR between 85% to 87% removal. Thus, between 50% to 90%, the cost of NO_x removal for LNB+SCR ranges from $3.43 to about $4.38/lb NO_x removed. At 90% removal, the cost effectiveness for SCR (alone) and LNB+SNCR+SCR is approximately the same as $4.45/lb at the same 90% control level. The cost-effectiveness for LNB+SCR is slightly less at $4.20/lb., Table 1-5.

Total capital investment for SCR is estimated at $2,630,400 and is outlined in Table B-20, Appendix B. This table illustrates that SCR capital cost is dominated by the price of catalyst ($655,400) based on the 1125 ft^3 required. Cost of exhaust gas heating and recovery equipment is included for an 83°C reheat which is accompanied by 65% recovery of the thermal input from the reheating. Since reheat is required for catalyst reactivity and the reheat recovery equipment costs are recovered in 1.7 years, the advantage of its use is apparent. Table B-20 also shows the effect on capital cost of a 15% retrofit factor $328,600 computed similar to a contingency factor. This is equivalent to a 20% retrofit factor computed as a combination of retrofit peculiar equipment plus contingency. The O&M costs for SCR were determined to be approximately 42% of annual costs which totalled $1,240,500 for 90% NO_x removal.

Total capital investment for LNB was estimated to be $85,200 in Table B-24 with total annual charges amounting to approximately $27,300. Cost effectiveness for the use of low NO_x burners with an estimated reduction in NO_x emissions of 40 percent is $0.12/lb.

Total capital investment for SNCR is estimated at $640,600 as shown in Table B-24 and total annual charges of $275,700 as detailed in Table B-25.

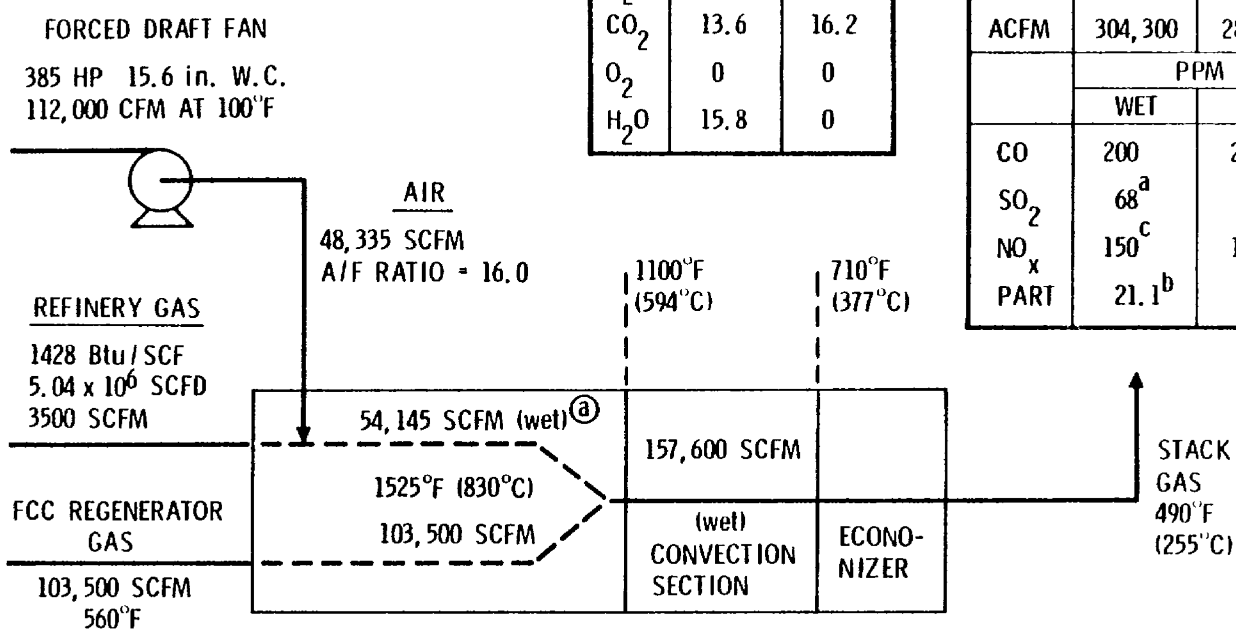
SCR capital and operating costs and associated catalyst/reactor sizes which were used for cost estimates for the various combinations of control technology are presented in Tables B-20 & B-25.

3.2.5 582 MMBtu/hr CO Boiler

3.2.5.1 Characteristics

Figure 3-25 is an operating schematic of a Combustion Engineering CO boiler rated at 275,000 lb/hr (steam) operating at 263 MMBtu/hr heat input, or 45% of capacity. The unit is gas-fired with 1428 Btu/SCF refinery gas and fluid catalytic cracker (FCC) regenerator gas, and utilizes 8 forced-draft tangential firing burners. Combustion takes place at a 16.0 air/fuel ratio based on a 3500 SCFM primary fuel flow. The FCC regenerator gas is introduced at 560°F at a rate of 103,500 SCFM. Composition of the FCC regenerator gas is also shown in Figure 3-25. For this gas composition a minimal amount of CO is present.

Combustion products enter the boiler's convection section at a temperature of about 1100°F (594°C) and then pass through



ⓐ	% WET	% DRY
N_2	70.5	83.8
CO_2	13.6	16.2
O_2	0	0
H_2O	15.8	0

	WET	DRY		
SCFM	157,600	149,100		
ACFM	304,300	287,000		
	PPM		lb/hr[c]	lb/10⁶ Btu[c]
	WET	DRY		
CO	200	211	—	—
SO_2	68[a]	72[a]	—	—
NO_x	150[c]	158[c]	181.1	0.602
PART	21.1[b]	22.3[b]	—	—

	%
N_2	85
CO_2	10
O_2	5
CO	200 ppm

CO BOILER
45% LOAD

COMBUSTION ENGINEERING
8 TANGENTIAL FIRING BURNERS

	% WET	% DRY
N_2	80.1	84.7
CO_2	11.2	11.8
O_2	3.3	3.5
H_2O	5.4	0

NOTES:

[a] AT 3% O_2

[b] $21.1 \frac{mg}{nm^3} = 0.0092$ grains/SCF

[c] 3% O_2, DRY AS NO_2, 45% LOAD

[d] 582 MMBtu/Hr Heat Input

Figure 3-25 Operating Characteristics of a 275,000 lb/hr (Steam) CO Boiler the economizer at 710°F (377°C). After leaving the economizer, exhaust gases leave the stack at a volumetric flow rate of approximately 304,300 ACFM, wet and 490°F (255°C).

Expected NO_x concentration, in the exhaust gas expressed as NO_2 is approximately 158ppm, dry at 3% O_2 (181.1 lb/hr or 0.602 lb/MMBtu). Particulates, SO_2 and CO have been reported as 22ppm (50 mg/nM^3), 72ppm, and 211ppm, respectively.

Several important factors must be considered in the application of either SCR or LNB control systems on a CO boiler and are discussed below. Undoubtedly, considerations affecting the applicability of SNCR are comparable to utility boilers, are Reference 3-2.

The longevity and efficiency of a catalyst installation is dependent to a great extent on particulates concentration and composition. The particulate concentration is about 50 mg/nM^3 in the unit studied. It is generally considered within the range that classifies the gas as a clean gas in the context of the particulates blinding or blocking the catalyst's active sites (Reference 3-3). Solely from this standpoint particulate concentration is not expected to significantly affect the performance of honeycomb or other parallel flow catalysts. Since the composition of the particulates is expected to be that of attrited FCC catalyst, the point may be raised that the particulate may promote oxidative reactions which would tend to lower the effectiveness of the reducing SCR catalyst. The presence of V_2O_5 in cracking residual fuels and the ensuing particulates together with the SO_2 in the gas is considered to be as severe a condition as could be expected in this regard. In the instance of a Japanese refinery using an SCR unit with a CO boiler operating with gas from the cracking of residual oil, no particulate-related problems were reported, Reference 3-4.

Fuji oil which has operated an SCR unit on a CO boiler at its Sodegaura refinery with dust levels of 60-70 mg/nM^3 experienced no significant performance degradation at the 90% level with the reactor operating temperature reported to be in the range of 385-405°C and observed no increase in system pressure drop. The latter being 115-125mm H_2O for a design value of 160mm, Reference 3-2. The reactor operating temperature was reported to be in the range of 385-405°C.

Factors involving the use of low NO_x Burners (LNB)are related to gas characteristics and existing burner configuration. Regarding gas characteristics, the possibility of NH_3 being present in the gas from the FCC has been raised by the operator of the unit being studied. Depending on the NH_3 concentration, which was not available, its presence would tend to reduce the effectiveness of low NO_x burners designed to influence the formation of thermal NO_x. The NH_3 could be expected to be oxidized as if were fuel-bound nitrogen. Therefore, if the NO_x being emitted from the boiler includes nitrogen from the FCC source,the NO_x reduction attributable to the LNB would likely be less than the generally accepted nominal of 40% for NO_x formed from thermal origins.

Other aspects of the CO boiler related to the burners include their location and configuration which are difficult to quantify. The tangential location of the burners in the boiler involved in this study tends to produce less NO_x relative to wall-fired or other locations. (Reference 3-5). The specific design of the existing burners incorporates alternating air and FCC-gas ports surrounding a central refinery gaseous fuel core. This configuration may tend to provide a flue gas recirculation effect thereby reducing the amount of NO_x relative to conventional burners, Reference 3-2, and possibly reducing the 40%-50% NO_x abatement increment generally attributable to replacement of conventional burners with LNB's. In addition, the size and complexity of LNB's may pose installation complexities in a tangentially fired unit.

Considering these effects, the amount of NO_x reduction resulting from the incorporation of LNB's is uncertain. Therefore, the amount of NO_x reduction is likely to be some undetermined amount less than the 40% that could be expected by replacing coventional burners in boilers. However, for purposes of this study a nominal 40% reduction was considered.

3.2.5.2 Cost Estimates

Figure 3-26 depicts the cost of alternative NO_x removal systems as a function of percent NO_x removal for a 582 MMBtu/hr CO boiler operating at 45% load. No exhaust gas reheat is required. The cost of NO_x removal is lowest for the combination of LNB+SCR between 70% to about 85% NO_x removal. At 86% removal LNB+SNCR+SCR becomes less expensive than LNB+SCR. At about 88%, LNB+SNCR+SCR and LNB+SCR are roughly equivalent in cost-effectiveness. At 90% NO_x removal SCR, LNB+SNCR+SCR, and LNB+SCR are all approximately \$3.50/lb. At this point, however SNCR+SCR is decidedly more expensive at approximately \$5.70/lb. More specifically, at 70% removal LNB+SCR is \$3.26/lb and at 85% is about \$3.42/lb NO_x removed, as contrasted to \$3.90/lb and \$3.60, respectively for SCR, Figure 3-26.

Total capital investment for an SCR installation designed to reduce NO_x emissions by 90% for this boiler CO when operating at full load is estimated at \$9,256,000. The major component of this cost, as delineated in Table B-26, Appendix B, is for 8045 ft^3 of catalyst which would cost approximately \$4,687,000. Retrofit costs are estimated to be in excess of one million dollars. At 45% operating load, O&M for SCR is expected to be approximately 48% of the annual costs which total \$4,892,000 (See Table B-28, Appendix B). For these estimates it was assumed that catalyst would be replaced every 2 years.

Eight low NO_x burners are required and were estimated at approximately \$161,000 including engineering, contingency, retrofit, and other miscellaneous capital costs. Annual costs were determined to be about \$51,600.

SNCR total capital investment was estimated at \$1,190,200 with annual costs totaling \$657,200, Tables B-30 and B-31.

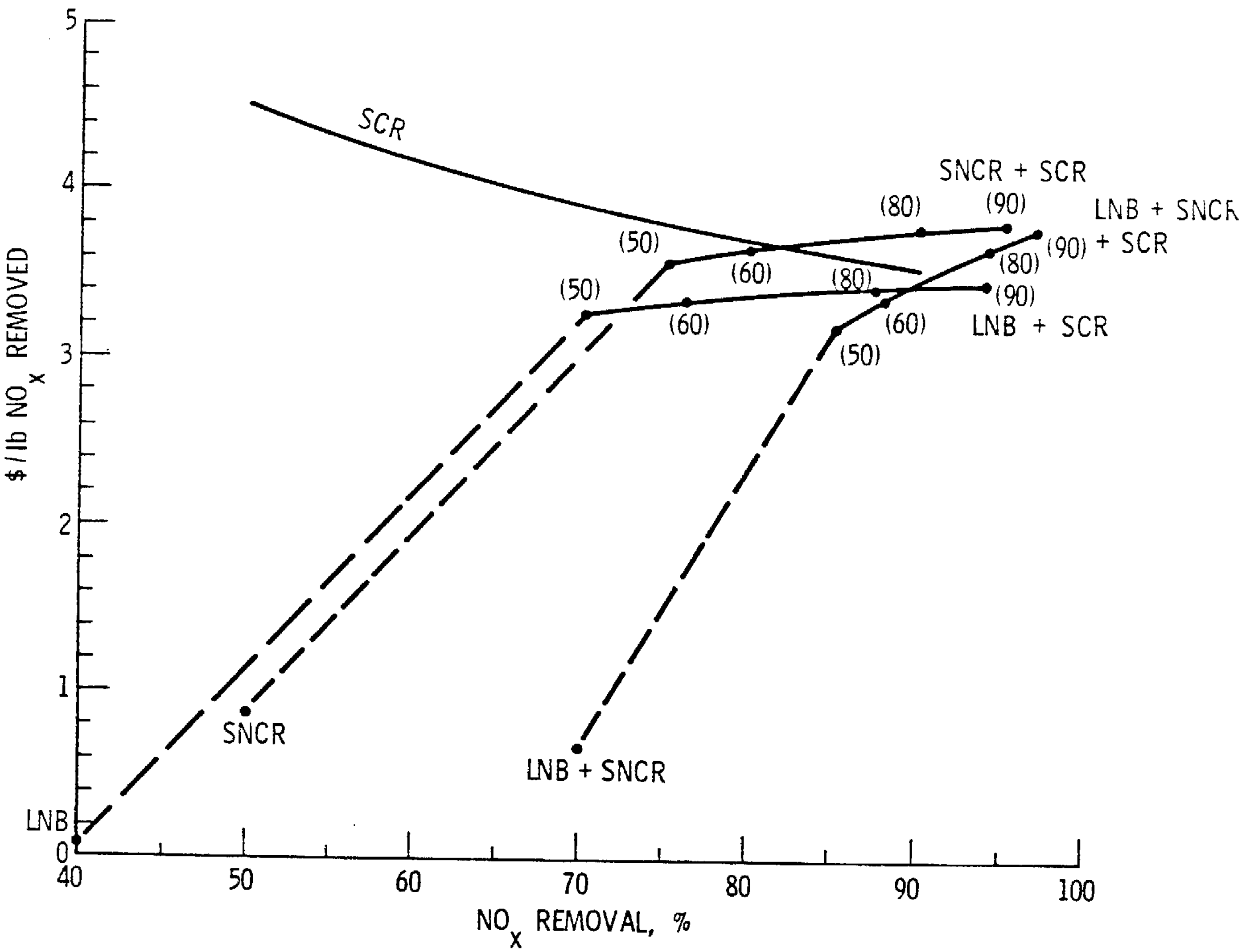


Figure 3-26 Cost of Alternative NO_x Removal Systems for a 582 MMBtu/Hr CO Boiler Operating at 45% Load-No Reheat Required; SCR Upstream of Economizer

3.3 Glass Melting Furnace (43.1 MMBtu/hr)

3.3.1 Characteristics

The operating characteristics of a 200 ton per day flint glass melting furnace (Reference 3-5) are represented in Figure 3-27. The furnace, when operated at 100% load with a 43.1 MMBtu/hr heat input rate is fueled by 1050 Btu/SCF natural gas fed at a rate of 41,000 CFH. Combustion air is introduced into one of a pair of regenerators which are used to preheat the combustion are thereby recovering heat from flue gas prior to being discharged up the stack. The regenerators are filled with refractory brick work and operate on an alternating basis. While one set of regenerators is being heated by combustion flue gas, the other is preheating the combustion air. Operation of the glass making process is continuous, with planned maintenance shutdowns occuring every several years.

The temperature of the flue gas entering the furnace is approximately 1650°F (990°C) and is cooled in the regenerator and exits at about 950°F (510°C). In the ejector, approximately 7100 SCFM ambient air is mixed with 15,150 SCFM flue gas and the mixture leaves the stack at a final temperature of 570°F (300°C).

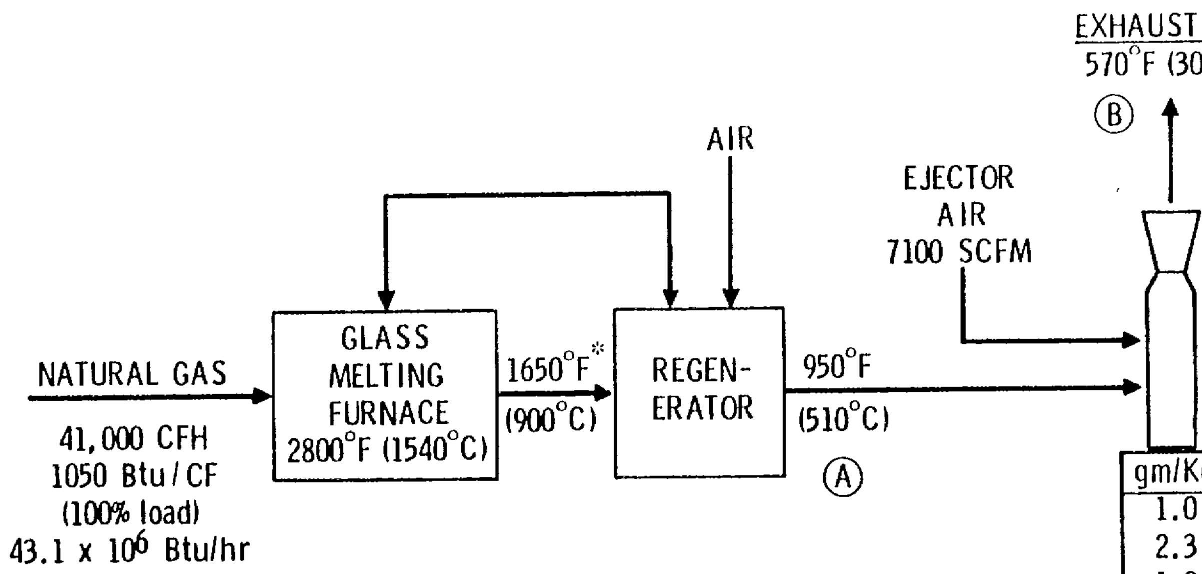
Emissions are reported as 38.4 lb/hr NO_x, as NO_2, 15.9 lb/hr SO_2, and 20.3 lb/hr particulates (Reference 3-4).

In addition to the three major control technologies (LNB, SNCR and SCR), it is recognized that a number of potentially efficient alternative NO_x control strategies are applicable to glass melting furnaces in general. In most cases these methods are likely to be implemented before post-combustion controls and would include process changes such as modifications to burner design, modifications to excess air levels, and electric boosting. These process changes were not within the scope of the study and were therefore not included in the analysis.

However, the unique nature of a glass melting furnace warrants consideration of certain aspects of the applicability of low-NO_x burners, SNCR, and SCR.

For example, it has been reported (Reference 3-2) that the quality of the glass is very sensitive to the characteristics and intensity of the flame and therefore could be affected by the application of LNB which in many instances have a less intense, more diffused type of flame. Although some form of combustion modification may be appropriate, the use of LNB appears questionable. Consequently, low NO_x burners were not considered as a NO_x control alternative and thus no cost estimates were included.

Particulate loading of the combustion gases is considered high for SCR application. Thus, the potential for catalyst poisoning or blinding is significant, Reference 3-2. Therefore, to maintain desired SCR performance and for cost estimating purposes, it was considered that catalyst was considerd to be replaced every year rather than every two



Ⓑ	WET	DRY
SCFM	22,560	21,570
ACFM	46,100	44,070
	% WET	% DRY
CO_2	12.5	13.2
N_2	69.3	73.3
O_2	12.8	13.5
H_2O	5.4	--

gm/Kg		lb/hr
1.0	SO_2	15.9
2.3	NO_x	38.4[a]
1.2	PARTICULATES	20.3[c]

Ⓐ	WET	DRY
SCFM	15,150	14,000
ACFM	43,200	39,900
	% WET	% DRY
CO_2	18.4	19.9
N_2	66.0	71.5
O_2	7.9	8.5
H_2O	7.6	--

gm/Kg[d]		lb/hr
1.0	SO_2	15.9
2.3	NO_x	38.4[a]
1.2	PARTICULATES	20.3[b]

NOTES:

[a] As NO_2

[b] 0.17 grains/dSCF (387 mg/Nm^3)

[c] 0.11 grains/dSCF (252 mg/Nm^3)

[d] Kg of glass pulled

3-27 Operating Characteristics of a 200 Ton/Day Flint Glass Melting Furnace years, as was done for the units emitting cleaner gases. A 15% factor was included in cost estimates to account for difficulty in retrofitting. However, space limitations are inherent with certain glass melting furnaces and facilities. Therefore, 50% would be more appropriate for a particularly encumbered site.

SNCR is suitable for application upstream of the regenerator where temperatures are in the optimum range for this non-catalytic process and conditions offer reasonable prospects for its implementation, Ref. 3-2.

Thus, for the flint glass melting furnace described, the only NO_x control combination considered for cost estimates was SNCR with SCR, where the degree of SCR control ranges from 50 to 90%. Also considered was SCR alone and SNCR alone.

3.3.2 Cost Estimates

Figure 3-28 is a summary of the cost of alternative NO_x removal systems as a function of the percent of NO_x removed from a gas-fired 200 ton per day flint glass melting furnace operating at 100% load. Gas temperatures are appropriate at accessible locations for SNCR and SCR and exhaust gas reheating is not required. Therefore the only alternatives considered, as discussed in Section 3.3.1, were SNCR alone, SCR alone, and the combination of SNCR + SCR.

At a 50% removal rate, SNCR alone has a lower cost at $0.90/lb than SCR alone, $1.90/lb. Above the nominal rate, 50% SNCR removal rate, SCR is the only alternative ranging from approximately $1.85/lb at 50% NO_x removal to $1.46/lb at 90% removal. The combination SNCR + SCR is not competitive at any level of control, with costs ranging from $1.82/lb at 70% removal to $1.85/lb at 90% removal.

Total capital investment, detailed in Table C-1, Appendix C, is estimated at $666,600 assuming a 15% retrofit cost (23% of the cost of a new installation). However, where severe space limitations exist, a 50% retrofit factor would be more appropriate. Catalyst cost, is based on a catalyst volume of 375 ft^3 contained within a reactor approximately 420 ft^3 in volume. Annual costs, given in Table C-3, Appendix C, indicate the high cost of catalyst replacement every year; i.e., $218,500. This results in the total O&M charges being approximately 59% of total annual costs of $442,900.

The total capital investment for SNCR is estimated at $383,900 with O&M charges totaling 31% of the total annual cost of $151,290.

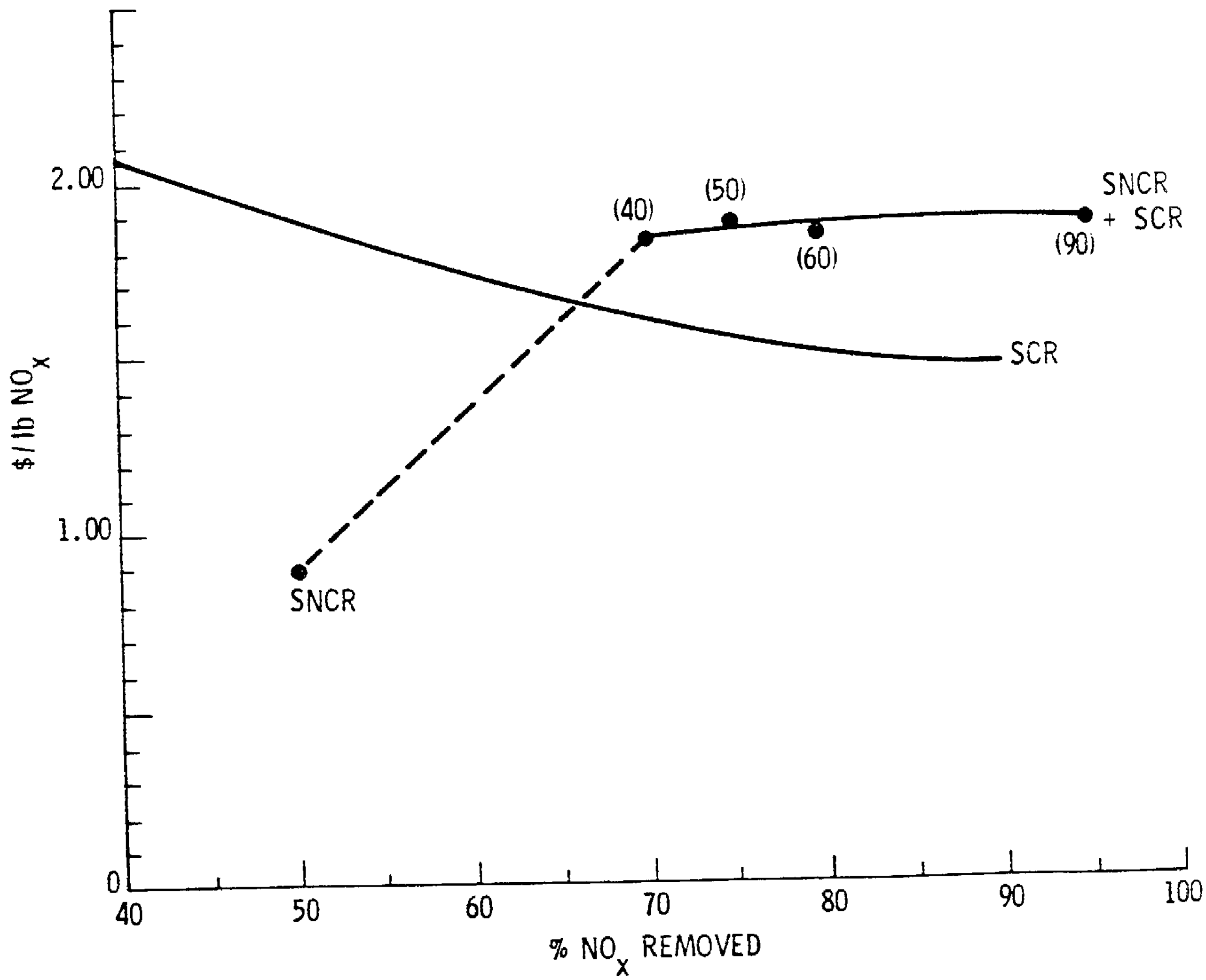


Figure 3-28 Cost of Alternative NO_x Removal Systems for a Gas-Fired Container Glass Melting Furnace Operating at 100% Load - No Reheat (1981 Dollars)

3.4 References

3-1 Personal Communication, Clark, J. M., Joy Industrial Equipment Company 2 October, 1981.

3-2 Leo, P. P., et al., Feasibility and Costs of Applying NO_x Controls on Stationary Emission Sources in California, Contract No A7-164-30, California Air Resources Board, May 1980.

3-3 Ando, J., NO_x Abatement for Stationary Sources in Japan, EPA-600/7-79-205 U.S. EPA, Office of Research & Development, August 1979.

3-4 Dr. Pohlenz testimony at 11/18/81 CARB hearing.

3-5 The McIlvaine Scrubber Manual, The McIlvaine Company, August 1981 and ARB Suggested Control Measure for the Control of Oxides of Nitrogen Emissions from Glass Melting Furnaces, State of California Air Resources Board, September 5, 1980.

APPENDIX A
REFINERY HEATERS

For the refinery heaters studied, the following data is included in Tables A-1 through A-33 of this appendix: components of estimated capital investment costs for an SCR system operating at a 90% removal rate; total capital investment cost for SCR systems operating at removal rates between 50 and 90%; estimated annual costs for SCR installations operating at removal levels from 50 to 90%; SCR catalyst size and reactor volume as a function of operating conditions; total capital investment cost for SNCR and LNB; and estimated annual cost for SNCR. All costs are stated in 1981 dollars. These costs are summarized and discussed in Section 3.0.

TABLE A-1

SCR CAPITAL COSTS AT 100% LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 65 MMBTU/HR REFINERY HEATER (1981 DOLLARS)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	$107,200	$107,200	---	A-1
CATALYST	74,900	74,900	---	A-2
DUCTING	3,500	1,800	1,700	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	19,100	---	A-3
NH_3 TANK	57,600	57,600	---	A-4
NH_3 VAPORIZER	3,600	3,600	---	A-1
NH_3 INJECTION EQUIP.	7,500	7,500	---	A-5
FLUE GAS FAN (30 HP)	24,600	--	24,600	A-5, A-6
REHEATER	N/A			---
HEAT RECOVERY EQUIP.	N/A			---
TOTAL CAPITAL COST	322,100	283,800	38,300	
		322,100		
ENGINEERING AND CONTINGENCY	80,500	70,800	9,700	A-1, A-10
RETROFIT	60,400[a]	--	60,400	A-1, A-7
PREPRODUCTION	11,500	10,100	1,400	A-1
FUNDS DURING CONSTRUCTION	6,000	5,300	700	A-7
TOTAL CAPITAL INVESTMENT	$480,500	370,000	110,500[b]	
		$480,500		

a. 15% OF ABOVE COSTS

b. 23.0% OF NEW INSTALLATION

TABLE A-2

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A GAS-FIRED 65 MMBTU/HR REFINERY HEATER - 89% LOAD (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	80	60	50
MAINTENANCE	9,700	9,000	7,600	6,800
OVERHEAD	2,900	2,700	2,300	2,000
OPERATING LABOR	5,500	5,100	4,300	3,900
NH_3	2,900	2,600	2,200	1,600
REPLACEMENT CATALYST[b]	34,600	32,300	27,200	24,400
FUEL	--	--	--	--
STEAM	100	100	100	100
H_2O	--	--	--	--
ELEC. POWER	5,000	4,700	3,900	3,500
TOTAL O&M	60.7[c] (32[d])	56.5 (32)	47.3 (31)	42.3 (31)
CAPITAL CHARGES	131.5 (68)	122.5 (68)	103.4 (69)	92.8 (69)
TOTAL ANNUAL COSTS	192.2 (100)	179.0 (100)	150.7 (100)	135.1 (100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY 2 YEARS

c. ($000)

d. % OF TOTAL ANNUAL COST

TABLE A-3

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A GAS-FIRED 65 MMBTU/HR REFINERY HEATER AT 100% LOAD

NO_x REMOVAL RATE, %	1981 DOLLARS
90	480,500
80	447,600
60	377,800
50	339,300

TABLE A-4

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR A GAS-FIRED 65 MMBTU/HR REFINERY HEATER[a]

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT[b]		
			W	H	L
100	90	128	5.5	20.0	5.5
100	80	119	5.5	18.7	5.5
100	60	100	5.5	15.7	5.5
100	50	90	5.5	14.1	5.5

a. UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 89% WHEN CHARACTERISTICS WERE OBTAINED

b. H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS

TABLE A-5

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A GAS-FIRED 65 MMBTU/HR REFINERY HEATER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL $DENO_x$)	210,700[b]	A-7
LOW NO_x BURNER, QTY = 24	145,800	A-8

a. INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

b INCLUDES $57,600 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM. EQUIPMENT SIZED FOR 100% LOAD.

TABLE A-6

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A GAS-FIRED 65 MMBTU/HR REFINERY HEATER (1981 DOLLARS)

COST FACTOR	ANNUAL COST	
OPERATING LABOR	$ 4,800	
OVERHEAD	1,900	
NH_3[b]	3,500	
H_2[b]	2,500	
STEAM[b]	200	
POWER[b]	4,600	
MAINTENANCE	6,300	
TOTAL O&M	23,900	(29)
ANNUAL CHARGE ON CAPITAL	57,600	(71)
TOTAL ANNUAL COST	81,500	(100)

a. FOR UNIT COSTS SEE TABLE 2-4

b. FOR 100% OPERATING LOAD.

c. VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

A.2 93 MMBTU/HR HEATER

TABLE A-7

SCR CAPITAL COSTS AT 100% LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 93 MMBTU/HR REFINERY HYDROTREATING REACTOR FEED HEATER-BASELINE CASE (WITHOUT REHEAT)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	95,800	95,800	--	A-1
CATALYST	135,700	135,700	--	A-2
DUCTING	3,000	1,500	1,500	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	19,100	--	A-3
NH_3 TANK	57,600	57,600	--	A-4
NH_3 VAPORIZER	4,400	4,400	--	A-1
NH_3 INJECTION EQUIP.	9,300	9,300	--	A-5
FLUE GAS FAN (25 HP)	23,000	--	--	A-5, A-6
REHEATER	N/A	--	--	--
HEAT RECOVERY EQUIP.	N/A	--	--	--
TOTAL CAPITAL COST	372,000	335,500	36,500	
		372,000		
ENGINEERING AND CONTINGENCY	93,000	89,900	9,100	A-1, A-10
RETROFIT	69,800[a]	--	69,800	A-1, A-7
PREPRODUCTION	15,900	14,300	1,600	A-1
FUNDS DURING CONSTRUCTION	6,900	6,200	700	A-7
TOTAL CAPITAL INVESTMENT	557,600	439,900	117,700[b]	
		557,600		

a. 15% OF ABOVE COSTS

b. 26.8% OF NEW INSTALLATION

TABLE A-8

SCR CAPITAL COSTS AT 100 % LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 93 MMBTU/HR REFINERY HYDROTREATING REACTOR FEED HEATER-WITH 89°C REHEAT (NO REHEAT RECOVERY)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS: NEW	NEW INSTALLATION VS. RETROFIT COSTS: RETROFIT	REF.
REACTOR	95,800	95,800	--	A-1
CATALYST	135,700	135,700	--	A-2
DUCTING	3,000	1,500	1,500	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-5
DAMPER	19,100	19,100	--	A-3
NH_3 TANK	57,600	57,600	--	A-4
NH_3 VAPORIZER	4,400	4,400	--	A-1
NH_3 INJECTION EQUIP.	9,300	9,300	--	A-5
FLUE GAS FAN (25 HP)	23,000	--	23,000	A-5, A-6
REHEATER	25,200	--	25,200	A-7
HEAT RECOVERY EQUIP.	N/A	--	--	A-10
TOTAL CAPITAL COST	397,200	335,500	61,700	
		397,200		
ENGINEERING AND CONTINGENCY	99,300	83,900	15,400	A-1, A-10
RETROFIT	74,500[a]	--	74,500	A-1, A-7
PREPRODUCTION	28,300	14,300	14,000	A-1
FUNDS DURING CONSTRUCTION	7,500	6,200	1,300	A-7
TOTAL CAPITAL INVESTMENT	606,800	439,900	166,900[b]	
		606,800		

a. 15% OF ABOVE COSTS

b. 37.9% OF NEW INSTALLATION

TABLE A-9

SCR CAPITAL COSTS AT 100% LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 93 MMBTU/HR REFINERY HYDROTREATING REACTOR FEED HEATER WITH 89°C REHEAT (WITH 65% REHEAT RECOVERY)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	95,800	95,800	—	A-1
CATALYST	135,700	135,700	--	A-2
DUCTING	3,000	1,500	1,500	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	19,100	--	A-3
NH_3 TANK	57,600	57,600	--	A-4
NH_3 VAPORIZER	4,400	4,400	--	A-1
NH_3 INJECTION EQUIP.	9,300	9,300	--	A-5
FLUE GAS FAN (25 HP)	23,000	--	23,000	A-5, A-6
REHEATER	25,200	—	25,200	A-9
HEAT RECOVERY EQUIP.[c]	198,600	--	198,600	A-10
TOTAL CAPITAL COST	595,800	335,500	260,300	
		595,800		
ENGINEERING AND CONTINGENCY	149,000	83,900	65,100	A-1, A-10
RETROFIT	111,700[a]	--	111,700	A-1, A-7
PREPRODUCTION	24,500	13,800	10.700	A-1
FUNDS DURING CONSTRUCTION	11,000	6,200	4,800	A-7
TOTAL CAPITAL INVESTMENT	892,000	439,400	452,600[b]	
		892,000		

a. 15% OF ABOVE COSTS

b. 103% OF NEW INSTALLATION

c. SIMPLE PAYBACK PERIOD FOR 100% LOAD & 65% HEAT RECOVERY: 2.1 YRS

TABLE A-10

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A GAS-FIRED 93 MMBTU/HR REFINERY HEATER AT 100% LOAD WITH REHEAT AND 65% REHEAT RECOVERY

NO_x REMOVAL RATE, %	1981 DOLLARS
90	892,000
60	715,800
50	640,000

TABLE A-11

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A GAS-FIRED 93 MMBTU/HR REFINERY HEATER-100% LOAD WITH FLUE GAS REHEAT NOT INCLUDED (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	80	60	50
MAINTENANCE	11,200	9,600	8,800	7,900
OVERHEAD	3,300	2,900	2,600	2,300
OPERATING LABOR	8,200	7,100	6,400	5,800
NH_3	5,300	4,100	3,600	3,000
REPLACEMENT CATALYST[b]	62,700	54,000	49,300	44,300
FUEL	N/A	N/A	N/A	N/A
STEAM	200	200	100	100
H_2O	--	--	--	--
ELEC. POWER	10,900	9,400	8,600	7,700
TOTAL O&M	101.8[c] (40[d])	87.3 (40)	79.4 (40)	71.1 (40)
CAPITAL CHARGES	152.6 (60)	131.4 (60)	119.9 (60)	107.7 (60)
TOTAL ANNUAL COSTS	254.4 (100)	218.7 (100)	199.3(100)	178.8(100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY 2 YEARS

c. ($000)

d. VALUES IN PARENS, ( ), DENOTE % OF TOTAL ANNUAL COST

TABLE A-12

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A GAS-FIRED 93 MMBTU/HR REFINERY HEATER-100% LOAD WITH 89°C EXHAUST GAS REHEAT AND 65% OF REHEAT RECOVERED (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	60	50	90[b]
MAINTENANCE	11,200	8,800	7,900	11,200
OVERHEAD	3,300	2,600	2,300	3,300
OPERATING LABOR	8,200	6,400	5,800	8,200
NH_3	5,300	3,600	3,000	3,800
REPLACEMENT CATALYST[c]	62,700	49,300	44,300	62,700
FUEL	49,800	33,400	27,900	35,800
STEAM	200	100	100	200
H_2O	--	--	--	--
ELEC. POWER	10,900	8,600	7,700	7,800
TOTAL O&M	151.6[e] (38[f])	112.8 (37)	99.0 (36)	133.0 (35)
CAPITAL CHARGES	244.1 (62)	195.8 (63)	175.1 (64)	244.1 (65)
TOTAL ANNUAL COSTS	395.7 (100)	308.6(100)	274.1(100)	377.1 (100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. 72% OPERATING LOAD

c. REPLACED EVERY 2 YEARS

d. 65% REHEAT RECOVERY

e. ($000)

f. VALUES IN PARENS, ( ), DENOTE % OF TOTAL ANNUAL COST

TABLE A-13

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR GAS-FIRED 93 MMBTU/HR REFINERY HEATER

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT		
			W	H	L
100	90	233	3.5	20.5	7.0
100	80	217	3.5	19.1	7.0
100	70	201	3.5	17.7	7.0
100	60	183	3.5	16.1	7.0
100	50	165	3.5	14.5	7.0

[a]. UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 72% WHEN CHARACTERISTICS WERE OBTAINED

[b]. H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS

TABLE A-14

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A GAS-FIRED 93 MMBTU/HR REFINERY HEATER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	247,300	A-7
LOW NO_x BURNER, QTY = 72	199,200	A-8

[a] INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

[b] INCLUDES $57,500 FOR NH_3 STORAGE FACILITIES (90 DAYS)

TABLE A-15

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A GAS-FIRED 93 MMBTU/HR REFINERY HEATER (1981 DOLLARS)

FACTOR	ANNUAL COST	
OPERATING LABOR	$ 8,200	
OVERHEAD	2,200	
NH_3[b]	6,600	
H_2[b]	7,100	
STEAM[b]	300	
POWER[b]	10,700	
MAINTENANCE	7,400	
TOTAL O&M	42,500	(38)
ANNUAL CHARGE ON CAPITAL	67,700	(62)
TOTAL ANNUAL COST	110,200	(100)

[a] FOR UNIT COSTS SEE TABLE 2-4

[b] FOR 100% OPERATING LOAD.

[c] VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

A.3 115 MMBTU/HR HEATER

TABLE A-16

SCR CAPITAL COSTS AT 100% LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 115 x 10^6 BTU/HR HYDROCRACKER REBOILER-NO REHEAT ($1981 DOLLARS)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS: NEW	NEW INSTALLATION VS. RETROFIT COSTS: RETROFIT	REF.
REACTOR	$ 153,600	$ 153,600	--	A-1
CATALYST	167,200	167,200	--	A-2
DUCTING	6,500	3,300	3,200	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	19,000	--	A-3
NH_3 TANK	115,200	115,200	--	A-4
NH_3 VAPORIZER	5,000	5,000	--	A-1
NH_3 INJECTION EQUIP.	13,200	13,200	--	A-5
FLUE GAS FAN (65 HP)	40,900	--	40,900	A-5, A-6
REHEATER	N/A			--
HEAT RECOVERY EQUIP.	N/A			--
TOTAL CAPITAL COST	544,800	488,700	56,100	
		$544,800		
ENGINEERING AND CONTINGENCY	136,200	122,200	14,000	A-1, A-10
RETROFIT	102,200[a]	--	102,200	A-1, A-7
PREPRODUCTION	22,600	20,300	2,300	A-1
FUNDS DURING CONSTRUCTION	10,100	9,100	1,000	A-7
TOTAL CAPITAL INVESTMENT	815,900	640,300	175,600[b]	
		815,900		

a. 15% OF ABOVE COSTS

b. 27.4% OF NEW INSTALLATION

TABLE A-17

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A GAS-FIRED 115 x 10^6 BTU/HR HYDROCRACKER REBOILER AT 90% LOAD

NO_x REMOVAL RATE, %	1981 DOLLARS
90	815,900
80	706,800
60	641,400
50	576,000

TABLE A-18

ANNUAL COST FOR AN SCR SYSTEM ON A GAS-FIRED 115 x 10^6 BTU/HR HYDROCRACKER REBOILER AT 90% LOAD - NO REHEAT(1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	80	60	50
MAINTENANCE	$ 16,000	$ 14,900	$ 12,600	$ 11,300
OVERHEAD	4,800	4,500	3,800	3,400
OPERATING LABOR	8,300	7,800	6,500	5,900
NH_3	10,500	9,300	7,000	5,900
REPLACEMENT CATALYST[b]	77,200	72,000	60,700	54,500
FUEL	--	--	--	--
STEAM	600	600	500	400
H_2O	--	--	--	--
ELEC. POWER	23,500	21,900	18,500	16,600
TOTAL O&M	140.9[c](39[d])	131.0 (39)	109.6 (38)	90.0 (38)
CAPITAL CHARGES	223.2(61)	208.2 (61)	175.5 (62)	157.6 (62)
TOTAL ANNUAL COSTS	$364.1(100)	$339.2(100)	$285.1(100)	$255.6(100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY 2 YEARS

c. ($000)

d. VALUES IN PARENS, ( ) DENOTE % OF TOTAL ANNUAL COST

TABLE A-19

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR A GAS-FIRED 115 x 10^6 BTU/HR HYDROCRACKER REBOILER

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT[b]		
			W	H	L
90[a]	90	287	7	22.5	7
90	80	262	7	20.5	7
90	60	226	7	17.7	7
90	50	203	7	15.9	7

a. UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 90% WHEN CHARACTERISTICS WERE OBTAINED

b. H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS

TABLE A-20

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A GAS-FIRED 115 MMBTU/HR HYDROCRACKER REBOILER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	\$ 330,800[b]	A-7
LOW NO_x BURNER, QTY = 12	38,500	A-8

[a] INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

[b] INCLUDES \$115,200 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM.

TABLE A-21

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A GAS-FIRED 115 MMBTU/HR HYDROCRACKER REBOILER (1981 DOLLARS)

COST FACTOR	ANNUAL COST	
OPERATING LABOR	$ 9,200	
OVERHEAD	3,000	
NH_3[b]	11,900	
H_2[b]	8,500	
STEAM[b]	500	
POWER[b]	23,300	
MAINTENANCE	9,900	
TOTAL O&M	66,300	(42)
ANNUAL CHARGE ON CAPITAL	90,500	(58)
TOTAL ANNUAL COST	156,800	(100)

a. FOR UNIT COSTS SEE TABLE 2-4

b. FOR 90 % OPERATING LOAD.

c. VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

A.4 164 MMBTU/HR HEATER

TABLE A-22

SCR CAPITAL COSTS AT 100% LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 164 MMBTU/HR REFINERY HEATER WITH 22°C EXHAUST GAS REHEAT AND 65% REHEAT RECOVERY (1981 DOLLARS)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	183,000	$183,000	--	A-1
CATALYST	255,100	255,100	--	A-2
DUCTING	8,700	4,400	4,300	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1.800	A-3
DAMPER	19,100	19,100	--	A-3
NH_3 TANK	172,800	172,800		A-4
NH_3 VAPORIZER	6,200	6,200	--	A-1
NH_3 INJECTION EQUIP.	13,000	13,000		A-5
FLUE GAS FAN (55 HP)	29,300	--	29,300	A-5, A-6
REHEATER	14,600	--	14,600	A-9
HEAT RECOVERY EQUIP.	67,500	--	67,500	A-10
TOTAL CAPITAL COST	793,400	665,700	127,700	
		793,400		
ENGINEERING AND CONTINGENCY	198,400	166,500	31,900	A-1, A-10
RETROFIT	148,800[a]	--	148,800	A-1, A-7
PREPRODUCTION	38,500	32,300	6,200	A-1
FUNDS DURING CONSTRUCTION	14,800	12,400	2,400	A-2
TOTAL CAPITAL INVESTMENT	1,193,900	876,900	317,000	
		$1,193,900		

a. 15% OF ABOVE COSTS

b.36.2% OF NEW INSTALLATION

TABLE A-23

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A GAS-FIRED 164 MMBTU/HR REFINERY HEATER AT 100% LOAD (1981 DOLLARS)

NO_x REMOVAL RATE, %	1981 DOLLARS
90	1,193,900
80	1,108,600
60	926,200
50	827,300

TABLE A-24

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A GAS FIRED 164 MMBTU/HR REFINERY HEATER OPERATING AT 88% LOAD - WITH 22°C REHEAT AND 65% REHEAT RECOVERY (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL			
	90	80	60	50
MAINTENANCE	21,800	20,300	17,100	15,400
OVERHEAD	6,500	6,100	5,100	4,600
OPERATING LABOR	12,700	11,800	10,000	9,000
NH_3	14,200	12,600	9,500	8,000
REPLACEMENT CATALYST[b]	117,700	109,800	92,600	83,100
FUEL	17,300	15,400	11,600	9,700
STEAM	600	500	400	300
H_2O	--	--	--	--
ELEC. POWER	25,500	23,800	20,100	18,000
TOTAL O&M	216.3[c] (40[d])	200.3 (40)	166.4(40)	148.1(40)
CAPITAL CHARGES	326.6 (60)	303.3 (60)	253.4(60)	226.3(60)
TOTAL ANNUAL COSTS	542.9(100)	503.6 (100)	419.8(100)	374.4(100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY 2 YEARS

c. ($000)

d. % OF TOTAL ANNUAL COST

TABLE A-25

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR A GAS-FIRED 164 MMBTU/HR REFINERY HEATER

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT [b]		
			W	H	L
100	90	438	8.5	20.5	8.5
100	80	408	8.5	19.1	8.5
100	60	343	8.5	16.1	8.5
100	50	308	8.5	14.4	8.5

[a] UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 88% WHEN CHARACTERISTICS WERE OBTAINED

[b] H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS

TABLE A-26

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A GAS-FIRED 164 MMBTU/HR REFINERY GAS HEATER (1981 DOLLARS)

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	$497,200[b]	A-7
LOW NO_x BURNER, QTY = 48	134,400	A-8

a. INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

b. INCLUDES $230,400 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM. EQUIPMENT SIZED FOR 100% HEATER LOAD.

TABLE A-27

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A 164 MMBTU/HR GAS-FIRED REFINERY HEATER (1981 DOLLARS)

COST FACTOR	ANNUAL COST	
OPERATING LABOR	$ 12,700	
OVERHEAD	4,500	
NH_3^b	18,600	
H_2^b	13,400	
STEAM[b]	800	
POWER[b]	8,000	
MAINTENANCE	14,900	
TOTAL O&M	72,900	(35)
ANNUAL CHARGE ON CAPITAL	136,000	(65)
TOTAL ANNUAL COST	208,900	(100)

[a.] FOR UNIT COSTS SEE TABLE 2-4

[b.] FOR 88 % OPERATING LOAD.

[c.] VALUES IN PARENS, (   ), DENOTE PERCENT OF TOTAL ANNUAL COST

A.5 435 MMBTU/HR HEATER

TABLE A-28

SCR CAPITAL COSTS AT 100 % LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 435 MMBTU/HR HYDROGEN REFORMING HEATER

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	270,700	270,700	--	A-1
CATALYST	903,000	903,000		A-2
DUCTING	23,900	12,000	11,900	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	3,700	--	A-3
DAMPER	19,100	19.100	--	A-3
NH_3 TANK	460,800	460,800	--	A-4
NH_3 VAPORIZER	11,200	11,200	--	A-1
NH_3 INJECTION EQUIP.	23,400	23,400	--	A-5
FLUE GAS FAN (335 HP)	70,400	--	70,400	A-5, A-6
REHEATER	NOT REQ	--	--	A-9
HEAT RECOVERY EQUIP.	NOT REQ	--	--	A-10
TOTAL CAPITAL COST	1,806,600	1,714,100	92,500	
		1,806,600		
ENGINEERING AND CONTINGENCY	451,700	433,600	18,100	A-1, A-10
RETROFIT	271,000[a]	--	271,100	A-1, A-7
PREPRODUCTION	93,500	89.800	3,700	A-1
FUNDS DURING CONSTRUCTION	32,800	31,500	1,300	A-7
TOTAL CAPITAL INVESTMENT	2,655,600	2,361,500	294,100[b]	
		2,655,600		

a. 15% OF ABOVE COSTS

b. 12% OF NEW INSTALLATION

TABLE A-29

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR GAS-FIRED 435 MMBTU/HR HYDROGEN REFORMING HEATER AT 100% LOAD (1981 DOLLARS)

NO_x REMOVAL RATE, %	1981 DOLLARS
90	2,655,600
80	2,364,300
60	1,781,500
50	1,490,000

TABLE A-30

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A GAS-FIRED 435 MMBTU/HR HYDROGEN REFORMING HEATER AT 80% LOAD (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	80	60	50
MAINTENANCE	68,500	63,900	53,900	48,400
OVERHEAD	20,500	19,100	16,100	14,500
OPERATING LABOR	29,800	27,800	23,400	21,000
NH_3	38,800	34,500	26,000	21,700
REPLACEMENT CATALYST[b]	416,800	371,000	279,300	233,400
FUEL	NOT REQ	N/R	N/R	N/R
STEAM	1,700	1,500	1,100	1,000
H_2O	--	--	--	--
ELEC. POWER	112,200	104,600	88,200	79,200
TOTAL O&M	688.3[c] (49[d])	622.4 (49)	488.0 (50)	419.2 (51)
CAPITAL CHARGES	726.6 (51)	646.9 (51)	487.4 (50)	407.7 (49)
TOTAL ANNUAL COSTS	1414.9 (100)	1269.3 (100)	975.4 (100)	826.9 (100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY 2 YEARS

c. ($000)

d. VALUES IN PARENS, ( ) DENOTE, % OF TOTAL ANNUAL COST

TABLE A-31

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR A GAS-FIRED 435 MMBTU/HR HYDROGEN REFORMING HEATER

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT[b]		
			W	H	L
100[a]	90	1550	12.5	18.5	12.5
100	80	1444	12.5	17.2	12.5
100	60	1215	12.5	14.5	12.5
100	50	1089	12.5	13.0	12.5

[a]UNIT SIZED TO OPERATE AT 100% LOAD. HEATER, WHEN STUDIED, WAS BEING OPERATED AT 80% LOAD.

[b]H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS.

TABLE A-32

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A GAS-FIRED 435 MMBTU/HR HYDROGEN REFORMING HEATER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL $DENO_x$)	\$ 939,800[b]	A-7
LOW NO_x BURNER, QTY = 136	376,100	A-8

[a]. INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

[b] INCLUDES \$460,800 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM. EQUIPMENT SIZED FOR 90% BOILER LOAD.

TABLE A-33

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A GAS-FIRED 435 MMBTU/HR HYDROGEN REFORMING HEATER (1981 DOLLARS)

COST FACTOR	ANNUAL COST	
OPERATING LABOR	$ 37,300	
OVERHEAD	8,500	
NH_3[b]	38,200	
H_2[b]	27,500	
STEAM[b]	1,700	
POWER[b]	15,500	
MAINTENANCE	28,200	
TOTAL O&M	156,900	(38)
ANNUAL CHARGE ON CAPITAL	257,100	(62)
TOTAL ANNUAL COST	$ 414,000	(100)

a. FOR UNIT COSTS SEE TABLE 2-4

b. FOR 100 % OPERATING LOAD.

c. VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

APPENDIX B
INDUSTRIAL BOILERS

For the refinery heaters studied, the following data is included in Tables B-1 through B-31 of this appendix: components of estimated capital investment costs for an SCR system operating at a 90% removal rate; total capital investment cost for SCR systems operating at removal rates between 50 and 90%; estimated annual costs for SCR installations operating at removal levels from 50 to 90%; SCR catalyst size and reactor volume as a function of operating conditions; total capital investment cost for SNCR and LNB; and estimated annual cost for SNCR. All costs are stated in 1981 dollars. These costs are summarized and discussed in Section 3.0.

B.1 4MMBTU/HR BOILER

TABLE B-1

SCR CAPITAL COSTS AT 100% LOAD, 90% NO_x REMOVAL FOR A GAS-FIRED 4 MMBTU/HR BOILER WITH 128°C REHEAT

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	30,400	30,400	--	A-1
CATALYST	5,400	5,400	--	A-2
DUCTING	400	400	--	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-5
DAMPER	19,100	19,100	—	A-3
NH_3 TANK	6,900	6,900	—	A-4
NH_3 VAPORIZER	700	700	—	A-1
NH_3 INJECTION EQUIP.	1,400	1,400	—	A-5
FLUE GAS FAN (5 HP)	10,600	--	10,600	A-5, A-6
REHEATER	4,500	--	4,500	A-9
HEAT RECOVERY EQUIP.	--[a]	--	--	A-10
TOTAL CAPITAL COST	103,500	76,400	27,100	
		103,500		
ENGINEERING AND CONTINGENCY	25,900	19,100	6,800	A-1, A-10
RETROFIT	19,400[b]	--	19,400	A-1, A-7
PREPRODUCTION	3,200	2,400	800	A-1
FUNDS DURING CONSTRUCTION	1,900	1,400	500	A-7
TOTAL CAPITAL INVESTMENT	153,900	99,300	54,600[c]	
		153,900		

a. NOT INCLUDED. EQUIPMENT ESTIMATED AT $30,000. SIMPLE PAYBACK EXCEEDS 8 YEARS

b. 15% OF ABOVE COSTS

c. 55% OF NEW INSTALLATION

TABLE B-2

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A GAS-FIRED 4 MMBTU/HR INDUSTRIAL BOILER AT 100 % LOAD

NO_x REMOVAL RATE, %	1981 DOLLARS
90	153,900
80	143,500
60	121,000
50	108,600

TABLE B-3

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A GAS-FIRED 4 MMBTU/HR AT 100% LOAD AND 128°C REHEAT (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	80	60	50
MAINTENANCE	$ 3,200	$ 3,000	$ 2,500	$ 2,300
OVERHEAD	900	800	700	600
OPERATING LABOR	300	300	200	200
NH_3	100	100	100	100
REPLACEMENT CATALYST[b]	2,500	2,300	2,000	1,800
FUEL	5,800	5,200	3,900	3,200
STEAM	NIL	NIL	NIL	NIL
H_2O	--	--	--	--
ELEC. POWER	1,000	900	800	700
TOTAL O&M	$13.8[c] (25[d])	12.6 (24)	10.2 (24)	8.9 (23)
CAPITAL CHARGES	42.1 (75)	39.1 (76)	33.1 (76)	29.7 (77)
TOTAL ANNUAL COSTS	55.9 (100)	51.7 (100)	43.3 (100)	38.6 (100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY 2 YEARS

c. ($000)

d. VALUES IN PAREN ( ) DENOTE % OF TOTAL ANNUAL COST

TABLE B-4

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR A GAS-FIRED 4 MMBTU/HR INDUSTRIAL BOILER

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT		
			W	H	L
100	90	9.3	2.5	11.8	2.5
100	80	8.7	2.5	11.0	2.5
100	60	7.3	2.5	9.3	2.5
100	50	6.6	2.5	8.3	2.5

[a] UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 100% WHEN CHARACTERISTICS WERE OBTAINED

[b] H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS.

TABLE B-5

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A GAS-FIRED 4 MMBTU/HR INDUSTRIAL BOILER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	$ 45,600[b]	A-7
LOW NO_x BURNER, QTY = 1	3,900	A-8

[a] INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

[b] INCLUDES $16,900 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM. EQUIPMENT SIZED FOR 100% LOAD.

TABLE B-6

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A GAS-FIRED 4 MMBTU/HR INDUSTRIAL BOILER (1981 DOLLARS)

FACTOR	ANNUAL COST	
OPERATING LABOR	$ 250	
OVERHEAD	410	
NH_3^b	160	
H_2^b	120	
STEAM[b]	10	
POWER[b]	940	
MAINTENANCE	1,400	
TOTAL O&M	3,290	(21)
ANNUAL CHARGE ON CAPITAL	12,500	(79)
TOTAL ANNUAL COST	$ 15,790	(100)

a. FOR UNIT COSTS SEE TABLE 2-4

b. FOR 100% OPERATING LOAD.

c. VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

B.2 22 MMBTU/HR BOILER

TABLE B-7

SCR CAPITAL COSTS AT 100 % LOAD, 90% NO_x REMOVAL FOR AN OIL-BURNING 22 MMBTU/HR (HOT WATER) BOILER - WITH 78°C REHEAT AND NO REHEAT RECOVERY

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	$ 68,600	$ 68,600	--	A-1
CATALYST	52,100	52,100	--	A-2
DUCTING	1,700	900	800	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	19,100	--	A-3
NH_3 TANK	57,600	57,600	--	A-4
NH_3 VAPORIZER	1,900	1,900	--	A-1
NH_3 INJECTION EQUIP.	3,900	3,900	--	A-5
FLUE GAS FAN (10 HP)	16,400	--	16,400	A-5, A-6
REHEATER	9,200	--	9,200	A-9
HEAT RECOVERY EQUIP.	--	--	--	--
TOTAL CAPITAL COST	254,600	216,200	38,400	
		254,600		
ENGINEERING AND CONTINGENCY	63,700	54,100	9,600	A-1, A-10
RETROFIT	47,700[a]	--	47,700	A-1, A-7
PREPRODUCTION	20,400	17,300	3,100	A-1
FUNDS DURING CONSTRUCTION	4,600	3,900	700	A-7
TOTAL CAPITAL INVESTMENT	$391,000	$291,500	$99,500[b]	
		$ 391,000		

a. 15% OF ABOVE COSTS

b. 34.1% OF NEW INSTALLATION

TABLE B-8

SCR CAPITAL COSTS AT 100 % LOAD, 90% NO_x REMOVAL FOR AN OIL-BURNING 22 MMBTU/HR (HOT WATER) BOILER - WITH 78°C REHEAT AND REHEAT RECOVERY (65 %)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	68,600	68,600	---	A-1
CATALYST	52,100	52,100	---	A-2
DUCTING	1,700	900	800	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	19,100	---	A-3
NH_3 TANK	57,600	57,600	---	A-4
NH_3 VAPORIZER	1,900	1,900	---	A-1
NH_3 INJECTION EQUIP.	3,900	3,900	---	A-5
FLUE GAS FAN (10 HP)	16,400	---	16,400	A-5, A-6
REHEATER	9,200	---	9,200	A-9
HEAT RECOVERY EQUIP.	67,500[c]	---	67,500	A-10
TOTAL CAPITAL COST	322,100	216,200	105,900	
		$322,100		
ENGINEERING AND CONTINGENCY	48,300	32,400	15,900	A-1, A-10
RETROFIT	56,600[a]	---	55,600	A-1, A-7
PREPRODUCTION	19,400	13,000	6,400	A-1
FUNDS DURING CONSTRUCTION	5,600	3,800	1,800	A-2
TOTAL CAPITAL INVESTMENT	451,000	265,400	185,600[b]	
		$451,000		

a. 15% OF ABOVE COSTS

b. 69.9% OF NEW INSTALLATION

c. SIMPLE PAYBACK PERIOD: 4.8 YR.

TABLE B-9

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR AN OIL-FIRED 22 MMBTU/HR INDUSTRIAL BOILER AT 100% LOAD DESIGNED FOR OIL SERVICE[a] (1981 $)

NO_x REMOVAL RATE, %	1981 DOLLARS
90	451,000
80	420,500
60	354,700
50	318,500

[a]78°C EXHAUST GAS REHEAT AND 65% REHEAT RECOVERY

TABLE B-10

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR AN OIL-OR GAS-FIRED 22 MMBTU INDUSTRIAL BOILER OPERATING AT 52% LOAD WITH 78°C REHEAT AND REHEAT RECOVERY (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL, %			
	OIL		GAS	
	90%	50%	90%	50%
MAINTENANCE	7,600	5,400	7,600	5,400
OVERHEAD	2,300	1,600	2,300	1,600
OPERATING LABOR	700	500	700	500
NH_3	1,500	800	500	300
REPLACEMENT CATALYST[b]	24,000	16,900	24,000	16,900
FUEL [c]	7,500	4,200	6,500	3,600
STEAM	100	100	100	100
H_2O	---	---	---	---
ELEC. POWER	2,600	1,800	2,600	1,800
TOTAL O&M	46.3[d] (27[e])	31.3 (26)	44.3 (26)	30.2 (26)
CAPITAL CHARGES	123.4 (73)	87.0 (74)	123.4 (73)	87.0 (74)
TOTAL ANNUAL COSTS	169.7 (100)	118.3 (100)	167.7 (100)	117.2 (100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY 2 YEARS

c. 65% REHEAT RECOVERY

d. ($000)

e. % OF TOTAL ANNUAL COST

TABLE B-11

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR AN OIL FIRED 22 MMBTU/HR INDUSTRIAL BOILER[a]

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT[b]		
			W	H	L
52	90	90	3.5	23.5	3.5
	80	84	3.5	21.9	3.5
	60	70	3.5	18.5	3.5
	50	63	3.5	16.6	3.5

[a] ALSO CAPABLE OF OPERATING ON NATURAL GAS

[b] H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS.

TABLE B-12

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR AN OIL-FIRED 22 MMBTU/HR INDUSTRIAL STEAM BOILER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	\$ 107,500[b]	A-7
LOW NO_x BURNER, QTY = 1	10,900	A-8

[a] INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

[b] INCLUDES \$27,500 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM. EQUIPMENT SIZED FOR 100% BOILER LOAD.

TABLE B-13

ANNUAL COST FOR SNCR (THERMAL DENOX SYSTEM FOR A 22 MMBTU/HR INDUSTRIAL STEAM BOILER
(1981 DOLLARS)

FACTOR	ANNUAL COST, $	
	OIL	NATURAL GAS
OPERATING LABOR	$ 1,400	$ 1,400
OVERHEAD	1,000	1,000
NH_3 [b]	2,100	800
H_2 [b]	1,500	800
STEAM[b]	100	100
POWER[b]	2,600	2,600
MAINTENANCE	3,200	3,200
TOTAL O & M	11,900 (40)	9,900 (25)
ANNUAL CHARGE ON CAPITAL	29,400 (60)	29,400 (75)
TOTAL ANNUAL COST	$ 41,300 (100)	39,300 (100)

[a]FOR UNIT COSTS SEE TABLE 2-4

[b]FOR 100% OPERATING LOAD

[c]VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

B.3 150 MMBTU/HR BOILER

TABLE B-14

SCR CAPITAL COSTS AT 100 % LOAD, 90% NO_x REMOVAL FOR AN OIL-FIRED 150 MMBTU/HR INDUSTRIAL STEAM BOILER WITH 68°C REHEAT AND 65% REHEAT RECOVERY

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	201,600	201,600	---	A-1
CATALYST	348,200	348,200	---	A-2
DUCTING	3,500	1,800	1,700	A-3
EXPANSION JOINTS	33,700	16,900	16,800	A-3
ELBOWS	3,100	1,600	1,500	A-3
DAMPER	31,500	31,500	---	A-3
NH_3 TANK	115,200	115,200	---	A-4
NH_3 VAPORIZER	5,900	5,900	---	A-1
NH_3 INJECTION EQUIP.	12,400	12,400	---	A-5
FLUE GAS FAN (55 HP)	22,200	---	22,200	A-5, A-6
REHEATER	15,700	---	15,700	A-9
HEAT RECOVERY EQUIP.	229,500	---	229,500	A-10
TOTAL CAPITAL COST	1,025,500	738,100	287,400	
		1,025,500		
ENGINEERING AND CONTINGENCY	256,400	184,500	71,900	A-1, A-10
RETROFIT	192,300[a]	---	192,300	A-1, A-7
PREPRODUCTION	49,500	35,600	13,900	A-1
FUNDS DURING CONSTRUCTION	19,000	13,700	5,300	A-7
TOTAL CAPITAL INVESTMENT	1,542,700	971,900	570,800[b]	
		1,542,700		

a. 15% OF ABOVE COSTS

b. 58.7% OF NEW INSTALLATION

TABLE B-15

TOTAL CAPITAL INVESTMENT OF AN SCR INSTALLATION AS A FUNCTION OF NO_x REMOVAL RATES FOR A 150 MMBTU/HR INDUSTRIAL STEAM BOILER AT 100% LOAD WITH 68°C REHEAT AND 65% HEAT RECOVERY

NO_x REMOVAL RATE[a], %	OVERALL NO_x REMOVAL RATE[a], %	TOTAL CAPITAL INVESTMENT, ($1981)
90	93	1,542,700
60	62	1,213,200
50	52	1,087,900

[a]BASED ON 19.6 LB/HR EMISSIONS FROM BOILER

[b]OVERALL REMOVAL RATE REQUIRED TO ACHIEVE 90% FROM BOILER (TOTAL EMISSIONS INCLUDE REHEATER NO_x EMISSIONS)

TABLE B-16

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM ON AN OIL-FIRED 150 MMBTU/HR INDUSTRIAL STEAM BOILER WITH 68°C REHEAT AND 65% REHEAT RECOVERY (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL, %[a] AT 100% LOAD			LOAD, % AT 90% REMOVAL	
	90	80	50	75	50
MAINTENANCE	25,500	23,800	18,000	25,500	25,500
OVERHEAD	7,600	7,100	5,400	7,600	7,600
OPERATING LABOR	12,500	11,700	8,800	12,500	12,500
NH_3	8,200	7,300	4,600	6,200	4,100
REPLACEMENT CATALYST[b]	160,700	149,800	113,500	160,700	160,700
FUEL	123,300	111,500	70,200	94,000	62,700
STEAM	400	400	400	300	200
H_2O	---	---	---	---	---
ELEC. POWER	8,200	7,600	5,800	6,900	5,400
TOTAL O&M	348.4[d] (45)	319.2 (45)	226.5 (43)	313.7 (43)	278.7 (40)
CAPITAL CHARGES	422.1 (55)	393.5 (55)	297.6 (57)	421.3 (57)	420.1 (60)
TOTAL ANNUAL COSTS	770.5 (100)	712.7 (100)	524.1 (100)	735.0 (100)	698.8 (100)

[a] BASED ON BOILER EMISSIONS

[b] FOR UNIT COSTS, SEE TABLE 2-4

[c] REPLACED EVERY 2 YEARS

[d] ($000)

[e] VALUES IN PARENS, ( ) DENOTES % OF TOTAL ANNUAL COST

TABLE B-17

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR AN OIL -FIRED 150 MMBTU/HR GAS FIRED INDUSTRIAL STEAM BOILER.

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT[b]		
			W	H	L
100	90	598	8.5	24.0	8.5
75	90	598	8.5	24.0	8.5
50	90	598	8.5	24.0	8.5
50	70	514	8.5	20.6	8.5
75	50	420	8.5	16.9	8.5
50	50	420	8.5	16.9	8.5

a. UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 48% WHEN CHARACTERISTICS WERE OBTAINED

b. H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS.

TABLE B-18

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR AN OIL-FIRED 150 MMBTU/HR INDUSTRIAL STEAM BOILER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	$ 253,000	A-7
LOW NO_x BURNER, QTY = (1)	24,380	A-8

[a] INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2- 3

TABLE B-19

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A 150 MMBTU/HR OIL-FIRED INDUSTRIAL STEAM BOILER (1981 DOLLARS)

COST FACTOR	ANNUAL COST	
OPERATING LABOR	$ 12,600	
OVERHEAD	2,300	
NH_3[b]	21,400	
H_2[b]	11,000	
STEAM[b]	400	
POWER[b]	18,300	
MAINTENANCE	7,600	
TOTAL O&M	73,600	(52)
ANNUAL CHARGE ON CAPITAL	69,200	(48)
TOTAL ANNUAL COST	$ 142,800	(100)

[a] FOR UNIT COSTS SEE TABLE 2-4

[b] FOR 100 % OPERATING LOAD.

[c] VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

B.4 336 MMBTU/HR BOILER

TABLE B-20

SCR CAPITAL COSTS AT 100 % LOAD[a], 90% NO_x REMOVAL FOR A GAS-FIRED 336 MMBTU/HR PROCESS STEAM BOILER WITH 83°C REHEAT AND 65% REHEAT RECOVERY (1981 DOLLARS)

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS: NEW	NEW INSTALLATION VS. RETROFIT COSTS: RETROFIT	REF.
REACTOR	286,500	286,500	--	A-1
CATALYST	655,400	655,400	--	A-2
DUCTING	27,800	13,900	13,900	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	9,600	9,500	A-3
NH_3 TANK	345,600	345,600	--	A-4
NH_3 VAPORIZER	9,600	9,600	--	A-1
NH_3 INJECTION EQUIP.	20,000	20,000	--	A-5
FLUE GAS FAN (150 HP)	49,100	--	49,100	A-5, A-6
REHEATER	35,500	--	35,500	A-9
HEAT RECOVERY EQUIP.	280,000[d]	--	280,000	A-10
TOTAL CAPITAL COST	1,752,700	1,352,700	400,000	
		1,752,700		
ENGINEERING AND CONTINGENCY	438,100	357,600	80,500	A-1, A-10
RETROFIT	328,600[b]	--	328,600	A-1, A-7
PREPRODUCTION	78,500	64,100	14,400	A-1
FUNDS DURING CONSTRUCTION	32,500	26,500	6,000	A-7
TOTAL CAPITAL INVESTMENT	2,630,400	2,200,900	429,500[c]	
		2,630,400		

a. UNIT SIZE TO HANDLE GASES AT 100% LOAD.

b. 15% OF ABOVE COSTS

c. 20% OF NEW INSTALLATION

d. SIMPLE PAYBACK PERIOD IS 1.7 YEARS

TABLE B-21

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A GAS-FIRED 336 MMBTU/HR PROCESS STEAM BOILER AT 100% LOAD (1981 DOLLARS)

NO_x REMOVAL RATE, %	1981 DOLLARS[b]
90	2,630,400
80	2,446,300
60	2,051,700
50	1,815,000

b. INCLUDES FLUE GAS REHEATER AND HEAT RECOVERY UNIT (65% REHEAT RECOVERY) COSTS.

TABLE B-22

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A GAS-FIRED 336 MMBTU/HR PROCESS STEAM BOILER AT 54% LOAD WITH 83°C REHEAT AND 65% REHEAT RECOVERY (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	80	60	50
MAINTENANCE	$ 55,800	$ 52,000	$ 43,900	$ 39,400
OVERHEAD	16,700	15,600	13,100	11,800
OPERATING LABOR	16,200	15,100	12,700	11,400
NH_3	30,300	27,000	20,300	17,000
REPLACEMENT CATALYST[b]	302,500	269,200	202,700	169,400
FUEL [c]	88,800	79,000	59,500	49,700
STEAM	1,300	1,200	900	700
H_2O	---	---	---	---
ELEC. POWER	9,200	8,600	7,200	6,500
TOTAL O&M	520.8[d] (42[e])	467.7(41)	360.3(39)	305.9(38)
CAPITAL CHARGES	719.7 (58)	669.3(51)	561.3(61)	496.6(62)
TOTAL ANNUAL COSTS	1240.5 (100)	1137.0 (100)	921.6 (100)	802.5 (100)

a. FOR UNIT COSTS, SEE TABLE

b. REPLACED EVERY 2 YEARS 2-4

c. 65% REHEAT RECOVERED. THERFORE 35% IS INCLUDED IN ANNUAL CHARGES

d. ($000)

e. VALUES IN PARENS, ( ), DENOTE % OF TOTAL ANNUAL COST

TABLE B-23

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR A GAS-FIRED 336 MMBTU/HR PROCESS STEAM BOILER

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT[b]		
			W	H	L
100	90	1125	11.8	22.6	11.8
100	80	1048	11.8	21.0	11.8
100	60	882	11.8	17.8	11.8
100	50	791	11.8	15.9	11.8

[a] UNIT SIZED TO OPERATE AT 100% LOAD. BOILER, WHEN STUDIED, WAS BEING OPERATED AT 54% LOAD.

[b] H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS.

TABLE B-24

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A GAS-FIRED 336 MMBTU/HR PROCESS STEAM BOILER (1981 DOLLARS)

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	\$ 640,600[b]	A-7
LOW NO_x BURNER, QTY = 4	85,225	A-8

[a]. INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

[b] INCLUDES \$230,400 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM. EQUIPMENT SIZED FOR 100% BOILER LOAD

TABLE B-25

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A GAS-FIRED 336 MMBTU/HR PROCESS STEAM BOILER (1981 DOLLARS)

COST FACTOR	ANNUAL COST	
OPERATING LABOR	$ 29,900	
OVERHEAD	5,800	
NH_3[b]	20,600	
H_2[b]	14,800	
STEAM[b]	900	
POWER[b]	9,200	
MAINTENANCE	19,200	
TOTAL O&M	100,400	(36)
ANNUAL CHARGE ON CAPITAL	175,300	(100)
TOTAL ANNUAL COST	275,700	(100)

a. FOR UNIT COSTS SEE TABLE 2-4

b. FOR 54 % OPERATING LOAD.

c. VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

B.5 582 MMBTU/HR CO BOILER

TABLE B-26

SCR CAPITAL COSTS AT 100 % LOAD, 90% NO_x REMOVAL FOR A 582 MMBTU/HR CO BOILER

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	913,800	913,800	--	A-1
CATALYST	4,687,000	4,687,000	--	A-2
DUCTING	24,000	12,000	12,000	A-3
EXPANSION JOINTS	20,000	10,000	10,000	A-3
ELBOWS	3,700	1,900	1.800	A-3
DAMPER	19,100	--	19,100	A-3
NH_3 TANK	292,000	292,200	--	A-4
NH_3 VAPORIZER	13,300	13,300	--	A-1
NH_3 INJECTION EQUIP.	27,900	27,900	--	A-5
FLUE GAS FAN (1200 HP)	136,300	--	136,300	A-5, A-6
REHEATER	N/A	--		A-9
HEAT RECOVERY EQUIP.	N/A	--		A-10
TOTAL CAPITAL COST	6,137,300	5,958,100	179,200	
		6,137,300		
ENGINEERING AND CONTINGENCY	1,534,300	1,489,500	44,800	A-1, A-10
RETROFIT	1,150,700[a]	--	1,150,700	A-1, A-7
PREPRODUCTION	319,400	310,100	9,300	A-1
FUNDS DURING CONSTRUCTION	114,300	111,000	3,300	A-7
TOTAL CAPITAL INVESTMENT	9,256,000	7,868,700	1,387,300[b]	
		9,256,000		

a. 15% OF ABOVE COSTS

b. 17.6% OF NEW INSTALLATION

TABLE B-27

TOTAL CAPITAL INVESTMENT FOR SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A 582 MMBTU/HR CO BOILER AT 100% LOAD (1981 DOLLARS)

NO_x REMOVAL RATE, %	1981 DOLLARS
90	$ 9,256,000
80	8,630,500
60	7,278,100
50	6,535,300

TABLE B-28

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A 582 MMBTU/HR CO BOILER AT 45% LOAD (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	80	60	50
MAINTENANCE	38,000	35,400	29,900	26,800
OVERHEAD	11,400	10,600	9,000	8,000
OPERATING LABOR	52,000	48,500	40,900	36,700
NH_3	74,200	66,000	49,700	41,600
REPLACEMENT CATALYST[b]	2,163,200	2,017,100	1,701,200	1,527,600
FUEL	--	--	--	--
STEAM	3,200	2,800	2,100	1,800
H_2O	--	--	--	--
ELEC. POWER	18,500	17,300	13,600	13,100
TOTAL O&M	2,360[c] (48[d])	2,197 (48)	1,846 (50)	1,656 (48)
CAPITAL CHARGES	2,532 (52)	2,361 (52)	1,866 (50)	1,788 (52)
TOTAL ANNUAL COSTS	4,892 (100)	4,558 (100)	3,712 (100)	3,444 (100)

a. FOR UNIT COSTS, SEE TABLE 2-4
b. REPLACED EVERY 2 YEARS
c. ($000)
d. VALUES IN PARENS, ( ), DENOTE % OF TOTAL ANNUAL COST

TABLE B-29

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR 582 MMBTU/HR CO BOILER

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT [b]		
			W	H	L
100[a]	90	8,045	30	24	30
100	80	7,502	30	22.4	30
100	60	6,308	30	18.8	30
100	50	5,654	30	16.9	30

a. UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 45% WHEN CHARACTERISTICS WERE OBTAINED

b. H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS.

TABLE B-30

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A 582 MMBTU/HR CO BOILER

CONTROL SYSTEM	1981 DOLLARS[a]	REF
SNCR SYSTEM (THERMAL DENOX)	$ 1,190,200[b]	A-7
LOW NO_x BURNER, QTY = 8	161,000	A-8

a. INCLUDES ENGINEERING, CONTINGENCY, RETROFIT AND OTHER COSTS PER TABLE 2-3

b INCLUDES $619,800 FOR A 3-MONTH SUPPLY NH_3 STORAGE SYSTEM. EQUIPMENT SIZED FOR

TABLE B-31

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A 582 MMBTU/HR CO BOILER (1981 Dollars)

FACTOR	ANNUAL COST	
OPERATING LABOR	$ 52,000	
OVERHEAD	10,700	
NH_3[b]	101,200	
H_2[b]	109,100	
STEAM[b]	4,400	
POWER[b]	18,500	
MAINTENANCE	35,700	
TOTAL O&M	331,600	(50)
ANNUAL CHARGE ON CAPITAL	325,600	(50)
TOTAL ANNUAL COST	657,200	(100)

a. FOR UNIT COSTS SEE TABLE 2-4

b. FOR 100 % OPERATING LOAD.

c. VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

APPENDIX C
GLASS MELTING FURNACE

For the glass melting furnaces studied, the following data is included in Tables C-1 through C-6 of this appendix: components of estimated capital investment costs for an SCR system operating at a 90% removal rate; total capital investment cost for SCR systems operating at removal rates between 50 and 90%; estimated annual costs for SCR installations operating at removal levels from 50 to 90%; SCR catalyst size and reactor volume as a function of operating conditions; total capital investment cost for SNCR and LNB; and estimated annual cost for SNCR. All costs are stated in 1981 dollars. These costs are summarized and discussed in Section 3.0.

In addition to the three major control technologies (LNB, SNCR and SCR), it is recognized that a number of potentially efficient alternative NO_x control strategies are applicable to glass melting furnaces in general. In most cases these methods are likely to be implemented before post-combustion controls and would include process changes such as modification to burner design, modification to excess air levels, and electric boosting. These process changes were not within the scope of the study and were therefore not included in the analysis.

TABLE C-1

SCR CAPITAL COSTS AT 100 % LOAD, 90% NO_x REMOVAL FOR A 200 TPD GAS-FIRED CONTAINER GLASS MELTING FURNACE WITH NO REHEAT

COMPONENT	COST 1981 DOLLARS	NEW INSTALLATION VS. RETROFIT COSTS		REF.
		NEW	RETROFIT	
REACTOR	86,300	86,300	--	A-1
CATALYST	218,500	218,500	--	A-2
DUCTING	2,500	2,500	--	A-3
EXPANSION JOINTS	20,400	10,200	10,200	A-3
ELBOWS	3,700	1,900	1,800	A-3
DAMPER	19,100	19,100	--	A-3
NH_3 TANK	57,600	57,600	--	A-4
NH_3 VAPORIZER	2,800	2,800	--	A-1
NH_3 INJECTION EQUIP.	5,800	5,800	--	A-5
FLUE GAS FAN (35 HP)	20,200	--	20,200	A-5, A-6
REHEATER	N/A			--
HEAT RECOVERY EQUIP.	N/A			--
TOTAL CAPITAL COST	436,900	404,700	32,200	
		436,900		
ENGINEERING AND CONTINGENCY	109,200	101,200	8,000	A-1, A-10
RETROFIT	81,900[a]	--	81,900	A-1, A-7
PREPRODUCTION	30,400	28,200	2,200	A-1
FUNDS DURING CONSTRUCTION	8,200	7,600	600	A-7
TOTAL CAPITAL INVESTMENT	666,600	541,700	124,900[b]	
		666,600		

a. 15% OF ABOVE COSTS

b. 23 % OF NEW INSTALLATION

TABLE C-2

TOTAL CAPITAL INVESTMENT OF SCR AS A FUNCTION OF NO_x REMOVAL RATES FOR A 200 TPD GAS-FIRED CONTAINER GLASS MELTING FURNACE AT 100% LOAD WITH NO REHEAT

NO_x REMOVAL RATE, %	1981 DOLLARS
90	666,600
60	522,600
50	507,400
40	443,700

TABLE C-3

ANNUAL COST FOR SCR NO_x REMOVAL SYSTEM FOR A 200 TPD GAS-FIRED CONTAINER GLASS FURNACE AT 100% LOAD (1981 DOLLARS)

COST FACTORS[a]	NO_x REMOVAL RATE, %			
	90	60	50	40
MAINTENANCE	13,100	10,300	9,200	8,100
OVERHEAD	3,900	3,100	2,800	2,400
OPERATING LABOR	4,000	3,100	2,800	2,500
NH_3	16,400	11,000	9,200	7,200
REPLACEMENT CATALYST[b]	218,500	170,400	153,000	133,300
FUEL	--	--	--	--
STEAM	700	500	400	300
H_2O	--	--	--	--
ELEC. POWER	3,900	3,000	2,799	2,400
TOTAL O&M	260.5[c] (59)[d]	201.4 (58)	180.1 (56)	156.1 (56)
CAPITAL CHARGES	182.4 (41)	143.0 (42)	138.8 (44)	121.4 (44)
TOTAL ANNUAL COSTS	442.9 (100)	344.4 (100)	318.9 (100)	277.6 (100)

a. FOR UNIT COSTS, SEE TABLE 2-4

b. REPLACED EVERY YEAR

c. ($000)

d VALUES IN PARENS, DENOTE PERCENT OF ANNUAL COST

TABLE C-4

SCR CATALYST SIZE AS A FUNCTION OF OPERATING CONDITIONS FOR A GAS-FIRED 200 TPD CONTAINER GLASS MELTING FURNACE

LOAD, %	NO_x REMOVAL RATE, %	CATALYST CHARACTERISTICS			
		VOL, FT^3	APPROX REACTOR SIZE, FT[b]		
			W	H	L
100	90	375	7.5	7.5	7.5
100	60	294	7.5	5.9	7.5
100	50	264	7.5	5.3	7.5
100	40	231	7.5	4.6	7.5

[a]. UNIT SIZED FOR FULL LOAD OPERATION. OPERATED AT 100% WHEN CHARACTERISTICS WERE OBTAINED

[b]. H IS THE AXIAL FLOW DIMENSION. W AND L ARE THE CROSS-SECTIONAL DIMENSIONS.

TABLE C-5

TOTAL CAPITAL INVESTMENT FOR SNCR SYSTEM AND LOW NO_x BURNER FOR A 200 TPD[a] GAS-FIRED CONTAINER GLASS MELTING FURNACE

CONTROL SYSTEM	1981 DOLLARS	REFERENCE
SNCR SYSTEM (THERMAL DENOX)	383,900[b]	A-7

[a] TONS/DAY

B INCLUDES $264,300 FOR NH_3 STORAGE FACILITIES

TABLE C-6

ANNUAL COST FOR SNCR (THERMAL DENOX) SYSTEM FOR A 200 TPD CONTAINER GLASS MELTING FURNACE (1981 DOLLARS)

FACTOR[a]	ANNUAL COST	
OPERATING LABOR	4,020	
OVERHEAD	3,460	
NH_3^b	22,380	
H_2^b	--	
STEAM[b]	980	
POWER[b]	3,880	
MAINTENANCE	11,520	
TOTAL O&M	46,240	(31)[c]
ANNUAL CHARGE ON CAPITAL	105,050	(69)
TOTAL ANNUAL COST	151,290	(100)

a. FOR UNIT COSTS SEE TABLE 2-4

b. FOR 100 % OPERATING LOAD.

c. VALUES IN PARENS, ( ), DENOTE PERCENT OF TOTAL ANNUAL COST

References

A-1 Maxwell, J.D., et al., Preliminary Economic Analysis of NO_x Flue Gas Treatment Processes Using TVA and EPRI Economic Premises, EPRI Contract No. RP783-3, Fossil Fuel Power Plants Department, EPRI, Palo Alto, January 1981.

A-2 Personal Communication, Clark, J. M., Joy Industrial Equipment Company, 2 October 1981.

A-3 Vanatur, W. M. and Neveril, R. B., "Estimating the Size and Cost of Ductwork", Chemical Engineering, McGraw-Hill, V.87, No. 26, 29 December 1980.

A-4 Page, J. S., Estimator's Manual of Equipment and Installation Costs, Gulf Publishing, Houston 1963.

A-5 Guthrie, K. M., Process Plant Estimating & Control, Craftsman, 1974.

A-6 Woods, D. R., Financial Decision Making in the Process Industry, Prentice-Hall, 1975.

A-7 Leo, P. P., et al., Feasibility and Costs of Applying NO_x Controls on Stationary Emission Sources in California, Contract No. A7-164-30, California Air Resources Board, May 1980.

A-8 Personal Communication, Bell, R. E., John Zink Company, 17 September 1981.

A-9 Choi, P. S. K., et al., Flue Gas Reheat for Wet FGD System, EPRI FP-361 (Battelle), February 1977.

A-10 Personal Communication, Enslin, P., Vaporphase, 19 August 1980.

CARB LIBRARY
07728